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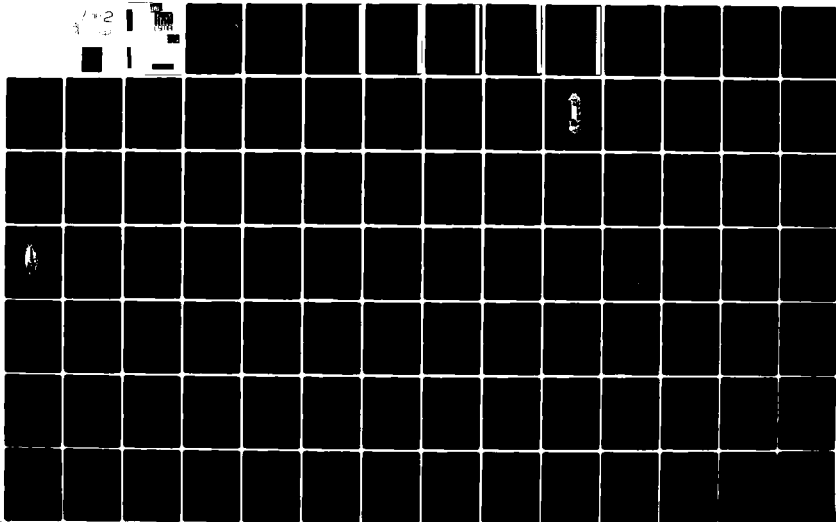
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NATIONAL BUREAU OF STANDARDS 1963 A

COLORADO SCHOOL OF MINES RESEARCH INSTITUTE

PARAMETERS AFFECTING THE CHARACTERISTICS OF
OIL SHALE-DERIVED FUELS

Prepared for

U.S. Army Mobility Equipment
Research and Development Command
Ft. Belvoir, Virginia

By

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ABSTRACT

Under the terms of the Defense Production Act, it is expected that as the U.S. oil shale industry develops, the Armed Forces of the United States will be the recipients of significant quantities of fuel products derived from shale oil. Lead responsibility for the preparation of fuel specifications for DF-1, DF-2, and DFA fuels has been charged to the U.S. Army, and in order to prepare realistic specifications for these fuels, the Army must be fully aware of all the parameters that will ultimately affect the characteristics of these fuels.

The objective of this research program was to collect, review, and evaluate all pertinent information dealing with the parameters that affect the properties of shale-derived fuels. To varying degrees, the critical parameters were found to be the source of the oil shale, method of retorting, retorting conditions, method and degree of upgrading, and refining techniques employed. With all other factors being equal, each of the above parameters will have an effect on the fuel properties; however, the flexibility inherent in the refining step permits all but the most major variations in shale oil properties to be compensated for in this operation.

This report describes all of the parameters that are likely to affect the characteristics of shale-derived fuels, with emphasis on the most significant parameters -- retorting and refining. The results of a comprehensive survey of potential shale oil refineries are presented, and forecasts are made regarding the likelihood of grass-roots refinery construction in the near- to mid-term. Based on contacts with shale oil producers and refiners, cost estimates for additional laboratory and pilot-scale research efforts are included.

MANAGEMENT SUMMARY

INTRODUCTION

Oil shale is a rock that contains kerogen, a solid organic material that cannot be extracted with conventional solvents but that breaks down into combustible liquids and gases when heated to approximately 900°F. The conversion of the kerogen into the liquid and gaseous products is known as _pyrolysis_, and the heating process is called _retorting_. The liquid product -- crude shale oil -- can be burned as a boiler fuel, converted into a synthetic crude (syncrude), or refined directly into liquid fuels and petrochemicals. The gaseous products can also be used as fuels in or near the retorting plant, or they can be upgraded to produce synthetic natural gas and be pipelined to more distant markets. Retorting also generates various waste products, principally the retorted or spent shale that remains after the shale oil and gases are removed.

Crude shale oil can be extracted from raw oil shale by either aboveground or in situ (in place) processing. In aboveground processing, the shale is mined and then heated in surface retorting vessels to pyrolyze the kerogen, converting it to shale oil for subsequent recovery. In situ processes involve the formation of large rubble chambers within the oil shale formation, followed by heating of the rubblized fragments to effect the kerogen pyrolysis and shale oil production.

Once extracted from the shale, the crude shale oil can be refined using conventional refining techniques. However, the presence of certain contaminants makes it necessary to carefully select the refinery operations that are used and the sequence in which they are used. The fuels that are produced in a carefully selected refining flow scheme will likely meet all specifications for performance and stability.

SUMMARY AND CONCLUSIONS

Shale oil can be produced from the Green River Formation by a variety of processes. Each of the locations from which the raw oil shale is derived and each of the retorting processes employed will produce an oil product with slightly different physical and chemical properties. The two most critical parameters that affect downstream processing are pour point and nitrogen content. The former is primarily a transportation consideration, as high pour point oils must be heated to make them transportable by either rail or pipeline. The nitrogen content, on the other hand, is a processing consideration, as it acts as a catalyst poison in conventional refining operations and must be removed by hydrotreating. Sulfur and trace metals contents are the next most critical considerations. The sulfur is easier to remove than the nitrogen and thus will be reduced to acceptable levels during the denitrification process. The trace metals, in particular arsenic, nickel, and vanadium, can be reduced to acceptable levels via established refining techniques.

Pour point reduction can be accomplished either by the addition of a chemical depressant, via hydrotreating, or by thermal treatment. Nitrogen, sulfur, and trace metals removal (upgrading) can be conducted either on site, prior to transport, or at the refinery site, prior to conversion into fuel products. Once the upgraded shale oil product (synthetic crude) reaches the refinery, a variety of conventional refining processes may be used to convert the oil into the desired slate of fuel products. The choice of processes is dependent upon the products desired as well as the equipment and financial constraints faced by the refiner. In general, the refining process

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represents the most important factor in determining the characteristics
of the final fuel products.

Based on the research conducted throughout the course of this pro-
ject, the following conclusions may be drawn:

- Given adequate economic justification, almost any quality
  of fuel product can be made from any raw shale oil feed-
  stock.

- The most difficult military fuel specification to meet when
  using shale oil as a feedstock is stability. The nitrogen
  compounds that cause storage instability, which are not
  removed by hydrotreating, must be removed via acid/clay
  treatment.

- The disposal of the acid sludge produced by large-scale
  acid/clay treating of finished products may represent a
  serious environmental problem, thus placing an increased
  emphasis on hydrotreating operations.

- At present, using existing equipment, only three refiner-
  ies in the Rocky Mountain/Great Lakes area are capable of
  refining raw shale oil to transportation fuels. Other
  refiners in the geographical region will have to make sub-
  stantial capital investments if they are to process raw
  shale oil.

- Any existing refinery can process shale oil that has been
  sufficiently hydrotreated to remove the nitrogen, sulfur,
  arsenic, and other contaminants.

- It is unlikely that a grass-roots refinery will be con-
  structed to process shale oil in the near- to mid-term.
  The reasons for this include:

  - existing excess refining capacity in the United
    States.

  - sufficient existing or proposed transportation sys-
    tems to transport shale oil to existing facilities.

  - ability of most refineries to process upgraded shale
    oil.

  - decreasing availability of conventional petroleum
    feedstocks.

  - anticipated conversion of many U.S. refineries to
    facilitate processing heavier petroleum crudes,
    increasing the number of facilities capable of
    accepting shale oil.

MANAGEMENT SUMMARY

- The costs involved in producing raw shale oil and refining
  it into transportation fuels for laboratory and pilot test-
  ing will approach $550,000.

DISCUSSION

BACKGROUND

Oil shale is a rock that contains kerogen, a solid organic material that cannot be extracted with conventional solvents but that breaks down into combustible liquids and gases when heated to approximately 900°F. The conversion of the kerogen into the liquid and gaseous products is known as pyrolysis, and the heating process is called retorting. The liquid product -- crude shale oil -- can be burned as a boiler feed, converted into a synthetic crude (syncrude), or refined directly into liquid fuel and petrochemicals. The gaseous products can also be used as fuels in or near the retorting plant, or they can be upgraded to produce synthetic natural gas and be pipelined to more distant markets. Retorting also generates various waste products, principally the retorted or spent shale that remains after the shale oil and gases are removed.

Oil shale deposits have been found on every inhabited continent. Asia has the most extensive resources overall, with a potential shale oil yield in excess of 700 trillion barrels. Australia and New Zealand have the least, with only about 120 trillion barrels. The world's resources total more than 2 quadrillion barrels, equivalent to about 600,000 barrels for each of the world's inhabitants. However, relatively little of the potential oil product could be recovered because of technical, economic, and environmental limitations.

Oil shale is found throughout the United States, as shown in Figure 1. The deposits in the central and eastern states underlie a vast area, but they are thin and yield relatively little oil, because the kerogen is deficient in hydrogen. However, they do offer some promise for the production of oil, gas, and by-products, such as sulfur and uranium. Both the U.S. Department of Energy (DOE) and private industry are evaluating this potential through a variety of research and development programs.

EXPLANATION

Tertiary deposits
Green River Formation in Colorado, Utah, and Wyoming; Monterey Formation, California; middle Tertiary deposits in Montana. Black areas are known high-grade deposits.

Mesozoic deposits
Marine shale in Alaska

Permian deposits
Phosphoria Formation, Montana

Devonian and Mississippian deposits (resource estimates included for hatchured areas only). Boundary dashed where concealed or where location is uncertain.
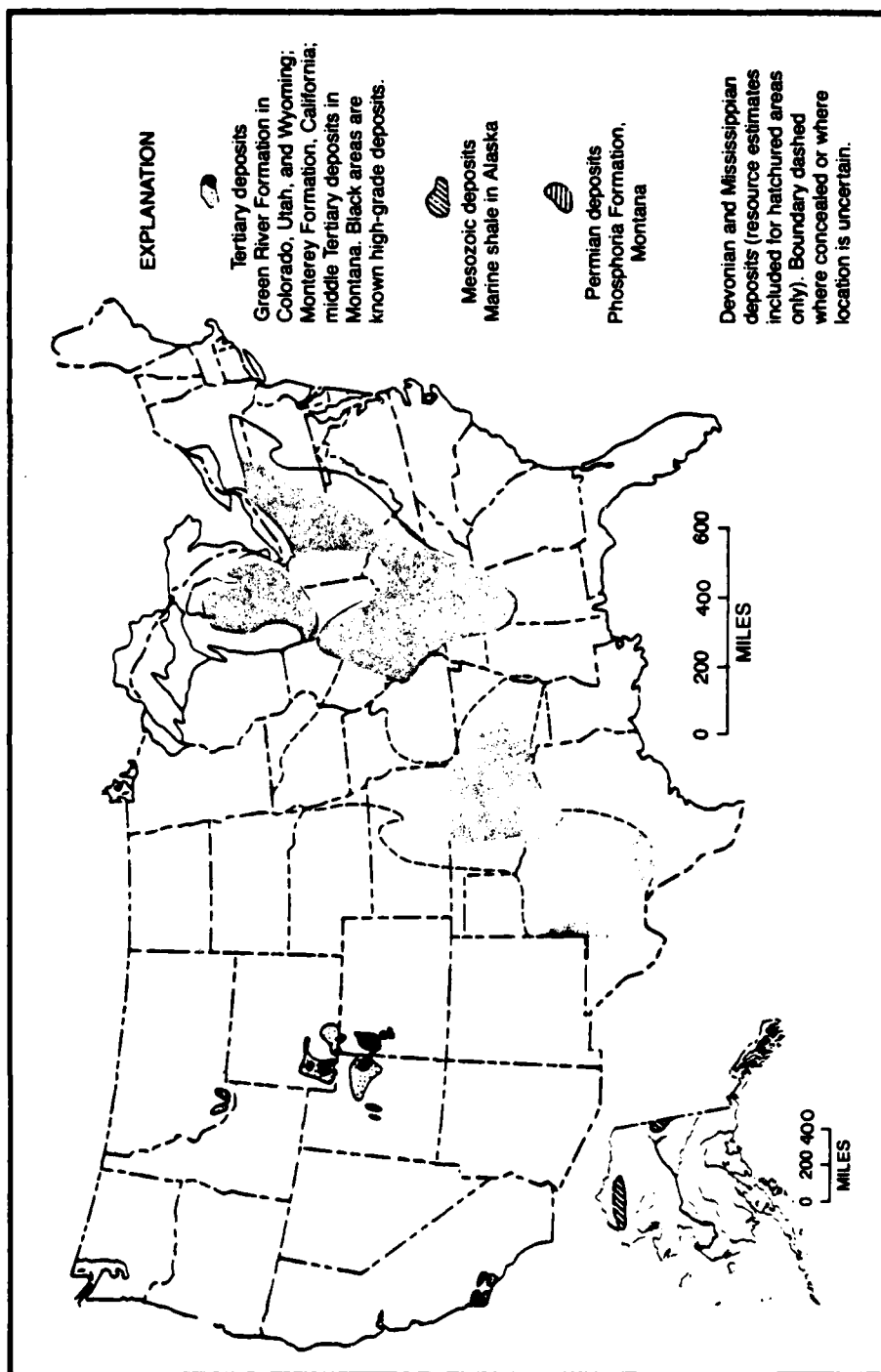
FIGURE 1

United States Oil Shale Deposits

The oil shale deposits in Colorado, Utah, and Wyoming occur principally in the Green River Formation. This formation was created 30 to 50 million years ago by the simultaneous deposition of organic debris and mineral silt on the bottoms of two large and long-lasting lakes. Heat, pressure, and time combined to solidify these raw materials into the mixture of kerogen and dolomitic limestone called Green River oil shale.

The Green River Formation has been divided into a number of discrete geological basins. The concentrations and characteristics of the oil shale vary appreciably between the basins. Wyoming oil shale, for example, has relatively little kerogen and is mixed with layers of rock with essentially no organic matter. The oil shale of the Uinta Basin in Utah and extreme western Colorado is richer than the Wyoming shales, but the minable deposits are still relatively thin compared with those in Colorado's Piceance Creek Basin. The Piceance Creek Basin constitutes the most extensive hydrocarbon deposit found anywhere in the world. Its oil shale beds are as much as 2,000 ft thick, and some layers can yield more than 2 bbl of shale oil per ton.

The total potential shale oil yield of the Green River Formation, some 8 to 11 trillion bbl, is far larger than the petroleum fields in the Middle East. If development were limited only by the size of the resource, the Piceance Creek Basin alone could satisfy all of the Nation's liquid fuel needs for thousands of years. However, as with the deposits elsewhere in the world, only a small fraction of the oil could be recovered economically with existing technologies. The estimates of recoverable shale oil are somewhat speculative, because the mining and processing methods have never been tested at full commercial scale. One commonly cited estimate is 400 billion bbl, equivalent to a 60-yr supply of liquid fuels for the United States at 1980 consumption levels.

Crude shale oil can be obtained by either aboveground or in situ (in place) processing. In aboveground processing, the shale is mined and then heated in

retorting vessels. In a true in situ (TIS) process, the deposit is first frac-
tured by explosives and then retorted underground. TIS is presently primitive,
although extensive research continues to be conducted. Modified in situ (MIS)
is a more advanced method in which a portion of the deposit is mined, and the
rest is shattered (rubbled) by explosives and is retorted underground. The mined
material can either be retorted on the surface or discarded.

The Green River oil shales may be extracted for aboveground processing by
either underground mining or surface mining methods. The most advanced under-
ground method is room and pillar mining, in which some of the oil shale is
removed to form large rooms, and the rest is left behind as pillars to support
the mine roof. This technique was first tested by the U.S. Bureau of Mines at
Anvil Points, Colorado and has been proposed for the Colony property near
DeBeque, Colorado. Overall, about 60% of the oil shale would be removed from
the mining horizon with this method. Higher recoveries would be possible with
surface mining, but its application would be limited to certain areas where the
overburden covering the oil shale beds is relatively thin. Open-pit mines,
similar to coal mines but much larger, could be used in some portions of the
Piceance Creek Basin, such as on federal lease Tract C-a. Strip mining, another
technique used for coal, could be used in several areas of the Uinta Basin.

Once the oil shale is mined, it must be heated to about 900°F to break down
the kerogen. A variety of aboveground retorts have been proposed to heat the
shale. They differ principally with respect to the nature of the heat-carrying
medium. In direct heated retorts, the medium is the mixture of combustion gases
that results when the residual carbon on the retorted shale is burned within the
retort by injecting air and recycled pyrolysis gases. The second type is the
indirect heated gas flow retort, in which the oil shale is contacted with gases
that are heated in a separate furnace outside of the retort vessel. No combus-
tion occurs within the retort itself. The third type is the indirect heated

retort in which heat is carried by a circulating stream of hot solids, such as spent shale or some inert material like sand or ceramic balls. As with the second type, the carrier is heated outside the retort vessel.

Alternatively, the oil shale may be left underground and retorted in situ (in place). As noted previously, this may be accomplished by either TIS techniques, in which the mining is minimal, or MIS methods in which about 20% to 40% of the oil shale is removed to create void volume.

There are also some novel processes that have interesting potential but are not as highly developed. These include heating by microwave or radio-frequency radiation, b cerial degradation, and the use of exotic solvents to decompose the kerogen. These are presently in the research and development stage and have not yet been proposed for commercial application.

Regardless of the recovery method used, the crude shale oil product will have a market as either a boiler fuel, a refinery feedstock, or petrochemical feedstock. In the near term, when production of shale oil from the Green River Formation is relatively small, the output may find applicability as a boiler fuel, replacing primarily No. 6 fuel oil and residual oil. However, even though this option is attractive due to the low investment required for implementation, the long-term boiler fuel market is questionable. The factors that contribute to this forecast include:

- Potential nitrogen oxide emissions which would preclude direct firing.

- The continued phasing out of oil-fired installations for new construction.

- A likely oversupply of conventional heavy fuel oil and residual oils due to the increasingly heavier feedstock supply.

- The possible nonimplementation of the Industrial Fuel Use Act (the act would preclude the use of conventional fuel oil for boilers).

The use of shale oil as a petrochemical feedstock, for the production of either aromatics or olefins, has been investigated by several researchers but has

not been studied in a large pilot or commercial scale. Indications are that hydrogenated shale oil is a desirable feedstock, and furthermore, the conversion to olefins may represent a very convenient method for dealing with the high nitrogen content. However, because the major petrochemical complexes in the United States are located principally on the Gulf Coast and East Coast, the logistics involved in supplying shale oil to these regions essentially precludes this application in the near term. As the shale oil industry develops, it may eventually be cost effective to develop a new petrochemical industry in the Rocky Mountain region, but this remains to be seen.

The use of shale oil as a refinery feedstock for the production of liquid fuels is considered by most industry observers to be the most viable market for shale oil. The composition of the shale oil feedstock is dependent on factors such as the source of the oil shale, the retorting method employed, the retorting conditions used, and the degree of upgrading. As will be discussed in later sections of this report, the source of the oil shale affects primarily the trace metals content rather than the gross physical and chemical properties of the oil. Thus, while slight benefits may accrue from processing shales from specific geographic locations, these benefits are minor compared with other considerations.

In general, retorting methods that involve high temperatures or product cracking due to recycle or refluxing (e.g., MIS) produce lighter, more desirable oils. Those processes that involve no product cracking generally yield heavy, viscous oil products. The trade-off is on the quantity of oil produced, the heavier oils representing a greater volume per ton of rock processed.

Raw shale oil is hydrogen-deficient relative to most conventional crudes and usually contains high concentrations of nitrogen and trace metals. Thus, to upgrade the material to be compatible with most available crude processing equipment, the carbon/hydrogen ratio must be decreased, and the contaminants must be

removed. The C/H reduction may be accomplished either by removing the carbon or adding hydrogen. Coking is an example of the former process, but this technique yields substantial quantities of coke, which is not a very marketable product in the northwestern part of Colorado. Hydrogen addition, on the other hand, simultaneously improves the physical and chemical properties of the product and removes the nitrogen and sulfur contents. The negative aspect of hydrogenation, of course, is the need for hydrogen manufacture, a fairly costly operation.

As each oil shale project developer proceeds to the commercial scale, a determination will have to be made as to whether the shale oil product to be marketed will be in the raw form or upgraded. To make this decision, factors such as upgrading cost versus improved market price, environmental regulations, project timing, available transportation methods, etc. must be considered. The status of major U.S. oil shale projects is shown in Table 1.

Once the shale oil product reaches the refinery, whether it is in the crude form or upgraded, a wide variety of refining techniques may be employed to efficiently convert the material into liquid fuel products. Later sections of this report will discuss these processes in detail. In general, however, shale oil has a lower concentration of both light ends and heavy ends than many conventional crudes. Thus, it is generally a better source of jet fuel, diesel fuel, and other heavier distillates than most petroleum crudes. Compared to liquids from coal, shale oil contains less aromatics, making it better suited to distillate production, whereas coal liquids contain higher aromatic contents, making them more suitable for gasoline production. It is ironic that in view of these comparisons, shale oil is actually becoming a more desirable feedstock as the typical product slate of refineries tends to shift away from gasoline toward the middle distillate fuels and as the average barrel of petroleum being refined gets heavier.

TABLE 1

Status of Major U.S. Oil Shale Projects

Project	Location	Proposed Technology	Production Target (BPD)	Status Summary
Rio Blanco Oil Shale Co.; Gulf; Standard of Indiana	Federal lease tract C-a; Colorado	MIS and Lurgi-Ruhrgas aboveground retorts	76,000	L-R retort module design in progress. Burn of first experimental in situ retort initiated.
Cathedral Bluffs Oil Shale project: Occidental Oil Shale; Tenneco	Federal lease tract C-b; Colorado	Occidental MIS	57,000 (1986)	Shaft sinking for MIS module development. Process development work being done at Logan Wash. PSD permit obtained for 5,000 bbl/d.
White River Shale project: Sunoco Energy Development; Phillips; SOHIO	Federal lease tracts U-a and U-b; Utah	Paraho aboveground retorts	100,000	Inactive because of litigation between Utah, the Federal Government, and private claimants over land ownership.
Colony development Operation: Exxon: TOSCO	Colony Dow West property; Colorado	TOSCO II aboveground retorts	46,000	Pipeline to Casper proposed. Work initiated on Battlement Mesa community. PSD permit acquired for 46,000 BPD.
Long Ridge project: Union Oil of California	Union property: Colorado	Union "B" aboveground retort	9,000	Site development underway.
Superior Oil Company; SOHIO; Cleveland Cliffs Iron Co.	Pacific property; Colorado	Superior aboveground retort	50,000	Design of 15,000 BPD module underway. Process testing in Cleveland completed.
Sand Wash project: TOSCO	State-leased land; Utah	TOSCO II aboveground retorts	50,000	Site evaluation and feasibility studies underway. Lease terms require $8 million investment by 1985. Preliminary efforts for shaft sinking conducted.
Paraho Development Corp.	Utah state lease near Vernal, Utah	Paraho agoveground retorts	10,000	Engineering design in progress.
Multi Mineral Corp.	Multi Mineral property; Colorado	"Re-in situ" retorting for multi-mineral recovery	N/A	Engineering design underway. Preliminary research conducted at USBM Horse Draw 10' bore.
Logan Wash project: Occidental Oil Shale; DOE	D. A. Shale property; Colorado	Occidental MIS	500	6 experimental retorts constructed and burned. Retorts 7 and 8 under construction.
Geokinetics, Inc.: DOE	State-leased land; Utah	Horizontal-burn true in situ	2,000 (1982)	Continuation of field experiments. About 10,000 bbl have been produced to date.
BX Oil Shale project; Equity Oil Co.; DOE	Equity property; Colorado	True in situ retorting with super-heated steam (Equity process)	Unknown	Steam injection begun and will continue for about 2 years. Oil production expected in 1980. Production rate has not been predicted.

OIL SHALE SOURCES

The properties of raw oil shale from the Green River formation vary consid-
erably over the lateral extent of the deposit and with depth of burial. These
variations occur in both the inorganic and organic fractions; however, variations
in the inorganic category are both quantitative and qualitative, whereas organic
variations are principally quantitative, that is, the inorganic rock matrix con-
tains different constituents depending upon the point of origin, as opposed to
merely different proportions of a standard set of constituents. For example,
some oil shale in the northern part of the Piceance Creek Basin contains the sod-
ium minerals nahcolite and dawsonite in fairly high concentrations, while areas
in the southern portion of the basin contain none. Some regions contain high
clay concentrations, sometimes occurring in lenses, whereas other zones contain
very little clay material. Variations in the organic fraction, on the other
hand, relate merely to how much organic matter is present in a given quantity of
shale, and not so much to the composition of the organic material itself.
Because the genesis of all Green River kerogen was essentially the same, being
composed of the same type of source material and exposed to the same geologic
conditions, the kerogen is essentially the same through the basin.

This is not to say that the shale oil produced from the kerogen is all the
same, as the varying inorganic compositions of the raw oil shale may affect the
kerogen pyrolytic process and shale oil recovery operations. For example, the
presence of nahcolite (naturally occurring sodium bicarbonate) in retorting shale
will tend to reduce the hydrogen sulfide concentration in the product gas stream
by reacting with the sulfur compounds to form sodium sulfate. This effect may
also be manifested in lowered sulfur concentrations in the product oil, although
documentation substantiating this is not available. Likewise, arsenic concentra-
tions are reportedly lower in shale oils produced from shale in the northern part

of Piceance Creek Basin than in shales produced from shales in the central and southern part of the basin.

However, the variations in shale oil composition resulting from variations in the oil shale source location are relatively minor compared with variations produced by differing retorting processes and retorting conditions.

CANDIDATE RETORTING PROCESSES

The following sections present descriptions of the six retorting technologies that have been judged by CSMRI to be the closest to commercial development in the United States. Each section includes some historical background on the development of the process as well as a technical description.

Paraho Process

Background

The Paraho retort is a refractory-lined vertical kiln that utilizes a downward flow of solids and an upward flow of gases to pyrolyze the kerogen contained in oil shale and to recover the resulting gases and shale oil vapors. The process was developed in the late 1960's by Development Engineers, Inc. (DEI) by modifying vertical kiln technology, which had been previously investigated, most notably, in the development of the USBM Gas Combustion process and the Brazilian Petrosix process. This modified kiln was tested for limestone calcining in cement plants in Texas and in South Dakota to verify the solids flow characteristics of the Paraho technology.[10, 141]

In May 1972, DEI signed a lease agreement with the U.S. Department of Interior for the use of the Anvil Points facility in conjunction with a proposed oil shale retorting program. The resulting "Paraho Oil Shale Project" was scheduled to run until August 1976 at a total cost of $10 million.[10] Funding for the project was provided by a consortium of 17 energy companies and engineering firms.

These companies were:

- Sohio Petroleum Company
- Southern California Edison Company
- Cleveland-Cliffs Iron Company
- Gulf Oil Corporation
- Arthur G. McKee and Company
- Kerr-McGee and Company
- Shell Development Corporation
- Standard Oil Company (Indiana)
- The Carter Oil Company (Exxon)
- Mobil Research and Development Corporation
- Webb-Gary-Chambers-McLoraine (Group)
- Sun Oil Company
- Texaco, Inc.
- Phillips Petroleum Company
- Atlantic Richfield Company
- Marathon Oil Company
- Chevron Research Company

In return for its financial support, each company was guaranteed a favorable royalty arrangement in any commercial application of DEI's technology. A new company, Paraho Development Corporation was formed to manage the project.

Two Paraho retorts were constructed at Anvil Points. A 4½-ft OD pilot-plant unit was built to investigate operating parameters and to define conditions for further testing in the 10½-ft OD semiworks retort. The retorts were designed to enable them to be operated in either the direct or indirect heated modes. In the direct heated mode, the heat for retorting is supplied by the combustion of the residual carbon on the spent shale. In the indirect heated mode, heat is supplied by recycled gases heated in an external furnace. A third mode is essentially a combination of the previous two. The raw shale used as feed for the retorting program was provided by reactivating the USBM room-and-pillar mine at Anvil Points.

As part of the program, approximately 10,000 bbl of crude shale oil was produced for subsequent refining studies by the U.S. Navy at the Gary Western refinery in Fruita, Colorado. These refining studies, conducted in 1975, produced a full range of fuels that were subsequently tested in a variety of military vehicles.[9]

In May 1975, Paraho Development Corporation released a prospectus that described plans to construct a full-size module capable of producing 7,300 bbl of crude shale oil per day. The plan did not receive adequate financial support, and progress slowed significantly when it was determined that a full Environmental Impact Statement (EIS) was required for the project.[10]

In 1976, the lease on the Anvil Points facility was extended to 1982. In the same year, the U.S. Energy Research and Development Administration (ERDA) announced plans for a $13 million project to produce 100,000 bbl of shale oil for refining and testing. DEI was awarded two contracts totalling approximately $2.1 million to refurbish facilities at Anvil Points and to continue the production and storage of shale oil at the site.

The 100,000 bbl of shale oil produced during the ERDA program was refined at the Standard Oil Company (Ohio) Toledo refinery under conditions that would maximize yields of JP-5 and diesel fuel marine (DFM). These fuels were of higher quality and had improved stability characteristics when compared with the products from the Gary Western refining run.[165]

In mid-1980, Paraho Development Corporation announced that it would construct a $200 million oil shale demonstration plant on its Utah state lease, 40 mi southeast of Vernal. Sponsors for the project include:

- U.S. Department of Energy
- Chevron Research Company
- Conoco, Inc.
- Davy McKee Corporation
- Mobil Research and Development Corp.
- Mono Power Company
- Phillips Petroleum Company
- Sohio Shale Oil Company
- Sunoco Energy Development Company
- Texas Eastern Synfuels, Inc.
- Cleveland-Cliffs Iron Company

In addition, Paraho Development Corporation announced in July 1980 that it had been awarded a $3.1 million grant by the U.S. Department of Energy for a 1-yr feasibility study of a commercial oil shale plant.[35]

Technology

The Paraho retort is a refractory-lined vertical kiln in which a moving bed of crushed shale flowing downward through the kiln is contacted with a counter-current flow of hot gases that pyrolyze the organic material in the shale and convey the resulting vapors out the top of the retort. Raw shale is fed into the top of the retort by means of a rotating "pant-leg" distributor, as shown in Figure 2. As the shale flows downward through the retort, it passes through a series of temperature zones, depicted in Figures 3 and 4, that determine the stage of the retorting process in which the shale is engaged. The first temperature zone that the shale encounters as it passes down the retort is the preheating or mist formation zone in which heat is transferred from the rising gases to the cool incoming shale. This has the effect of preheating the shale prior to retorting, thereby increasing overall thermal efficiency. The second zone through which the shale passes is the retorting zone. In this zone, the shale encounters hot gases rising from the combustion zone in the direct heated mode or from the heating zone in the indirect heated mode. The hot gases heat the shale to a temperature that is sufficiently high to pyrolyze the kerogen. The resulting vapors are then swept from the retort by the upward flow of gases.

The next zone into which the shale passes is that in which the heat for retorting is developed. This portion of the retort distinguishes the direct heated mode of operation from the indirect heated. In the direct heated mode, sufficient air is injected into the retort to cause combustion of the residual carbon present on the retorted shale. In some cases, additional heat is supplied by injecting and burning a portion of the product gas. In the indirect heated mode, a stream of product gas is heated in an external furnace and then injected into the retort. Fuel for the furnace is supplied by a stream from the product gas line. In a commercial installation, this fuel could be either product gas, residual carbon, or heavy shale oil product.

RAW SHALE

ROTATING SPREADER

REFRACTORY

COLLECTORS

DISTRIBUTORS

DISTRIBUTORS

DISTRIBUTORS

MOVING GRATE

SHALE MOVED
THROUGH GRATE

OFF-GAS

GAS/AIR

GAS/AIR
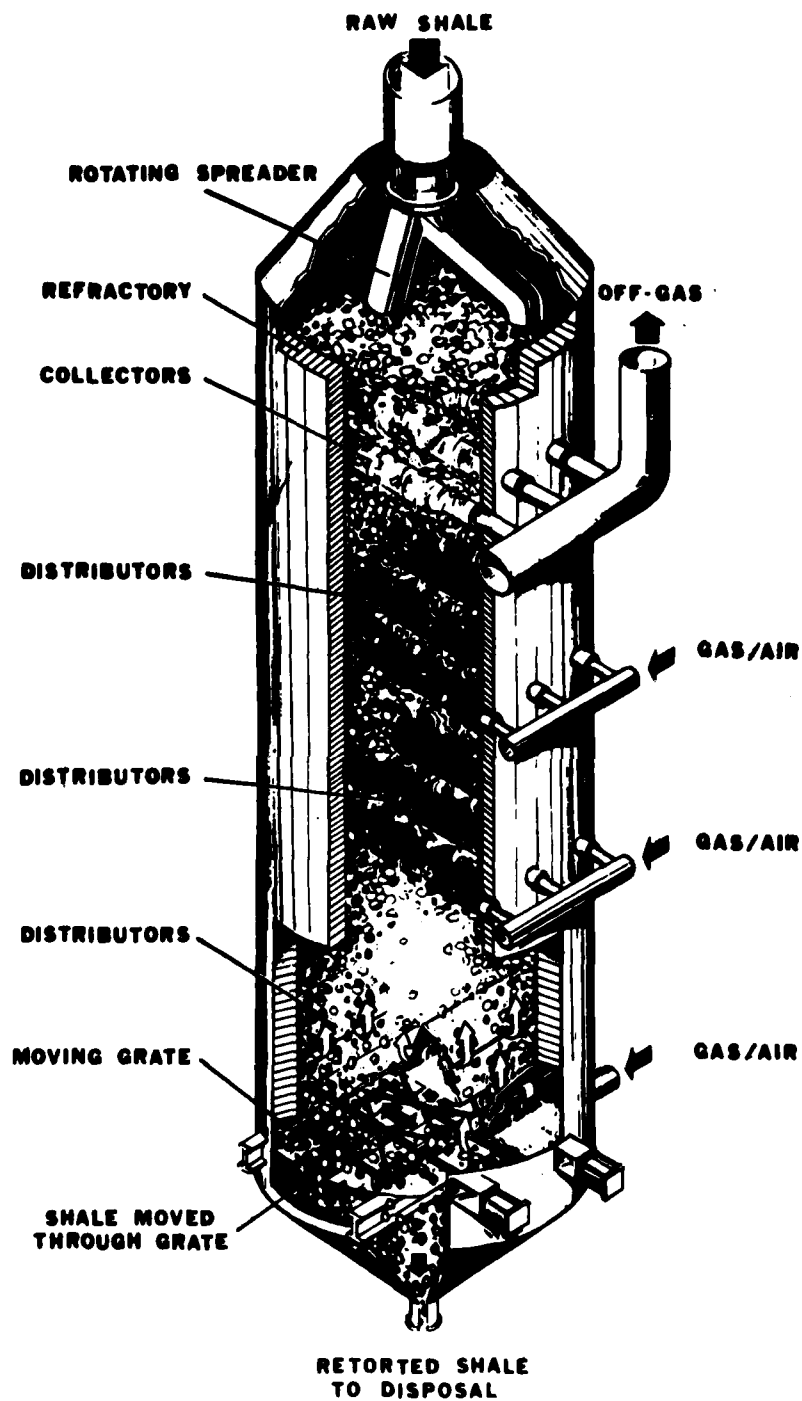
GAS/AIR

RETORTED SHALE
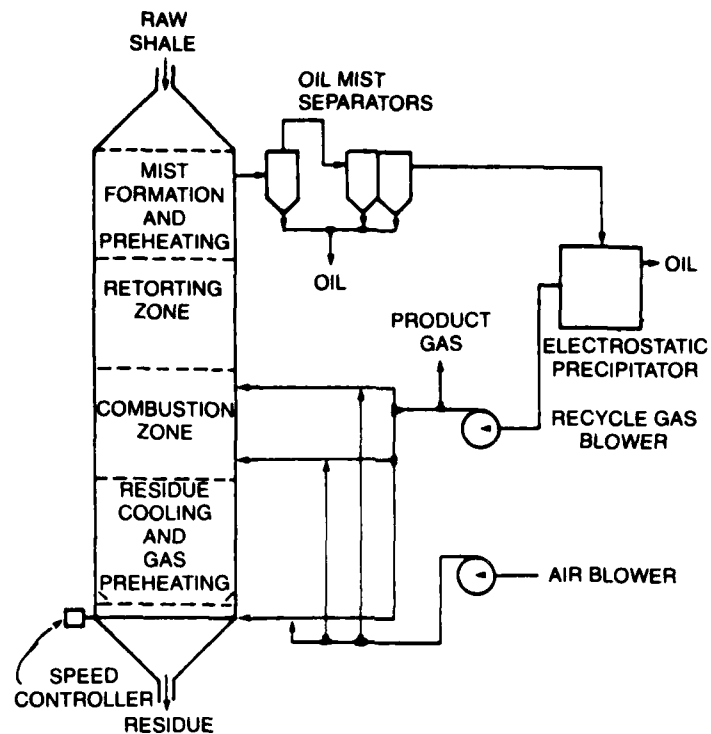TO DISPOSAL

FIGURE 2

Paraho Retort
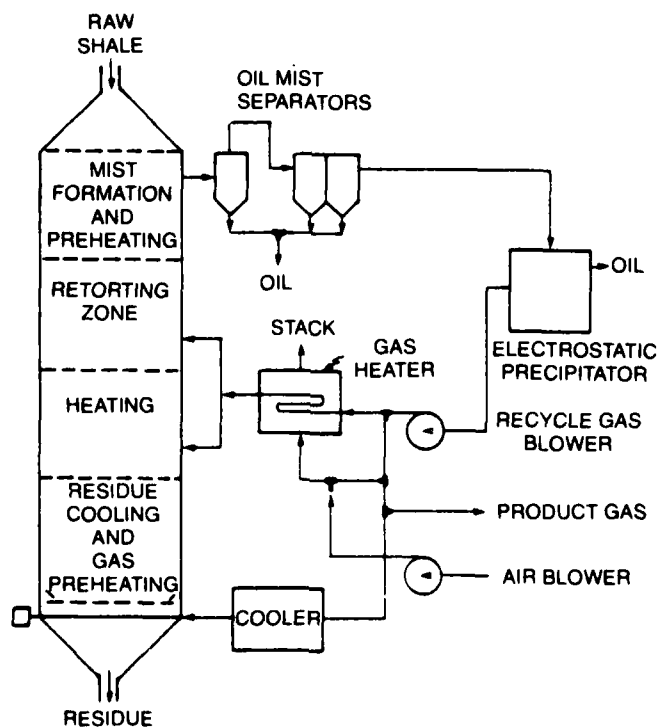
FIGURE 3

Paraho Retort - Direct Heated Mode

FIGURE 4

Paraho Retort - Indirect Heated Mode

After passing through the combustion (or heating) zone, the shale passes through the cooling zone. In this zone, heat is transferred from the hot shale to a stream of cool product gas that is injected at the bottom of the retort. The cooled shale then passes out the bottom of the retort through a patented grate mechanism used to control the velocity of the shale through the retort and also to maintain an even downward flow of shale over the cross section of the retort.

There are several significant items that arise as a result of the differences between the two modes of operation. The first item is the thermal efficiency of the two modes. In the indirect heated mode, a valuable source of energy, in the form of the residual carbon left on the spent shale, is not utilized. This lost energy is compensated for by burning a portion of the product gas in a furnace to provide heat for retorting, thus decreasing the net energy yield from the process. As noted, however, this residual carbon may be recovered in a commercial operation through direct combustion or gasification in an external unit. When operated in the direct heated mode, the residual carbon is burned off the spent shale within the retort itself.

A second difference stems from the fact that, in the direct heated mode, a significant quantity of air is injected into the retort and burned. The resulting combustion gases dilute the product gas causing it to have a markedly lower heating value than the product gas from the indirect heated mode. As shown in Table 2, gas produced in the direct heated mode has a higher heating value (HHV) of 102 Btu/scf, while gas produced in the indirect heated mode has a HHV of 885 Btu/scf, very close to that of natural gas.[73] Because of this large disparity between the qualities of the two product gases, there is a corresponding disparity between their values. Gas from the direct heated Paraho retort is used exclusively as fuel for the processing plant while gas from the indirect heated retort may have a value on the open market.

TABLE 2

Paraho Retorting Gas Properties (dry basis)

| | Volume, % | |
	Direct Heated	Indirect Heated
H_2	2.5	24.8
N_2	65.7	0.7
O_2	0	0
CO	2.5	2.6
CH_4	2.2	28.7
CO_2	24.2	15.1
C_2H_4	0.7	9.0
C_2H_6	0.6	6.9
C_3	0.7	5.5
C_4	0.4	2.0
H_2S	2,660 ppm	3.5
NH_3	2,490 ppm	1.2
HHV	102 Btu/scf	885 Btu/scf

A third difference, and possibly the most important from the standpoint of this study, lies in the quality of the oil products produced by the two modes of operation. Table 3 presents a comparison of several properties of crude shale oil from both modes of operation. The oils are similar in most respects, with the difference lying principally in the pour points of the two liquids. The oil product from the indirect heated retort has a pour point that is 20°F lower than that of the product from the direct heated retort.[73] While this lower pour point will not cause radical differences in the properties of the oils, it indicates that a slightly lighter product is produced in the indirect heated retort. This difference in product quality has an effect on the extent and severity of upgrading that may ultimately be required.

TABLE 3

Paraho Retorting Product Oil Quality

	Direct Heated	Indirect Heated
Gravity, °API	21.4	21.7
Viscosity, SUS at 130°F	90	68
Viscosity, SUS at 210°F	46	42
Pour Point, °F	85	65
Ramsbottom Carbon, wt %	1.7	1.3
Water Content, vol %	1.5	1.4
Solids, BS, wt %	0.5	0.6

Union Oil Process

Background

Union Oil's involvement with oil shale has extended over the last 50 yr, with acquisition of oil shale reserves in Colorado having begun in the 1920's. Union has been developing oil shale retorting processes for more than 30 yr with the result being the development of three variations of a vertical kiln retort: Retort A, Retort B, and the Steam Gas Recirculation (SGR) retorts. All three retorts rely on the operation of a "rock pump" that provides for the upward flow of solids and the downward flow of gases through a retort having the shape of an inverted cone.

The first of the three retorting processes to be developed was Retort A, shown in Figure 5. This retort utilizes the upward flow of solids and downward flow of gases with heat being provided by combustion of the residual carbon remaining on the spent shale following the pyrolysis of the organic fraction. Pilot plants with capacities of 2 and 50 tpd were tested at Union's California research center, and, in 1957, a unit with a nominal capacity of 350 tpd was built at Union's property located approximately 15 mi north of Parachute, Colorado.[10] This unit was 40 ft tall, 17 ft in diameter, and used a rock pump $5\frac{1}{2}$ ft in diameter.

The next retort to be developed was Retort B, shown in Figure 6. Retort B pyrolyzes the kerogen contained in the shale by utilizing an indirect mode of heating the shale in which one stream of product gas is burned in a furnace to heat another stream of product gas. The heated gas is then circulated through the retort to provide the heat necessary for pyrolysis.

In June 1974, Union announced the development of still another process for removing oil from shale. The Steam Gas Recirculation (SGR) process, shown in Figure 7, is a modified Retort A in which the spent shale is sent to a gasifier to produce synthesis gas for injection into the retort to provide heat for
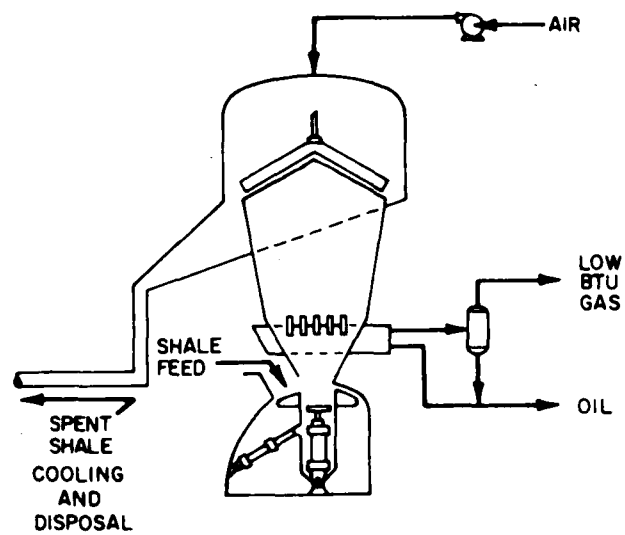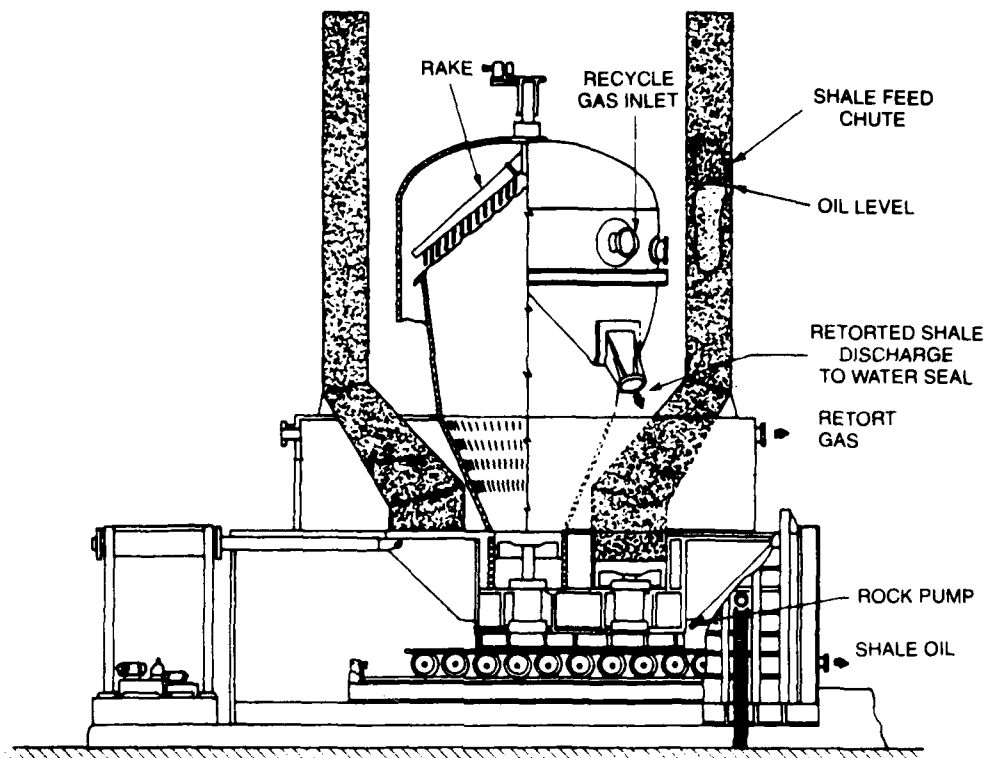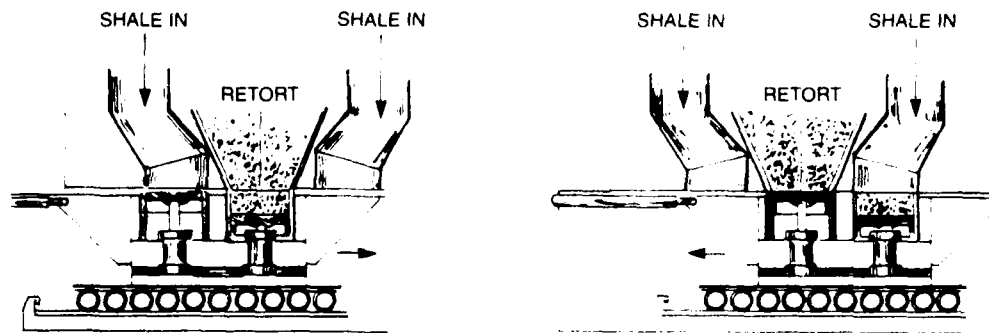
FIGURE 5

Union Oil Retort A

A. The Retorting System

B. Rock Pump Detail

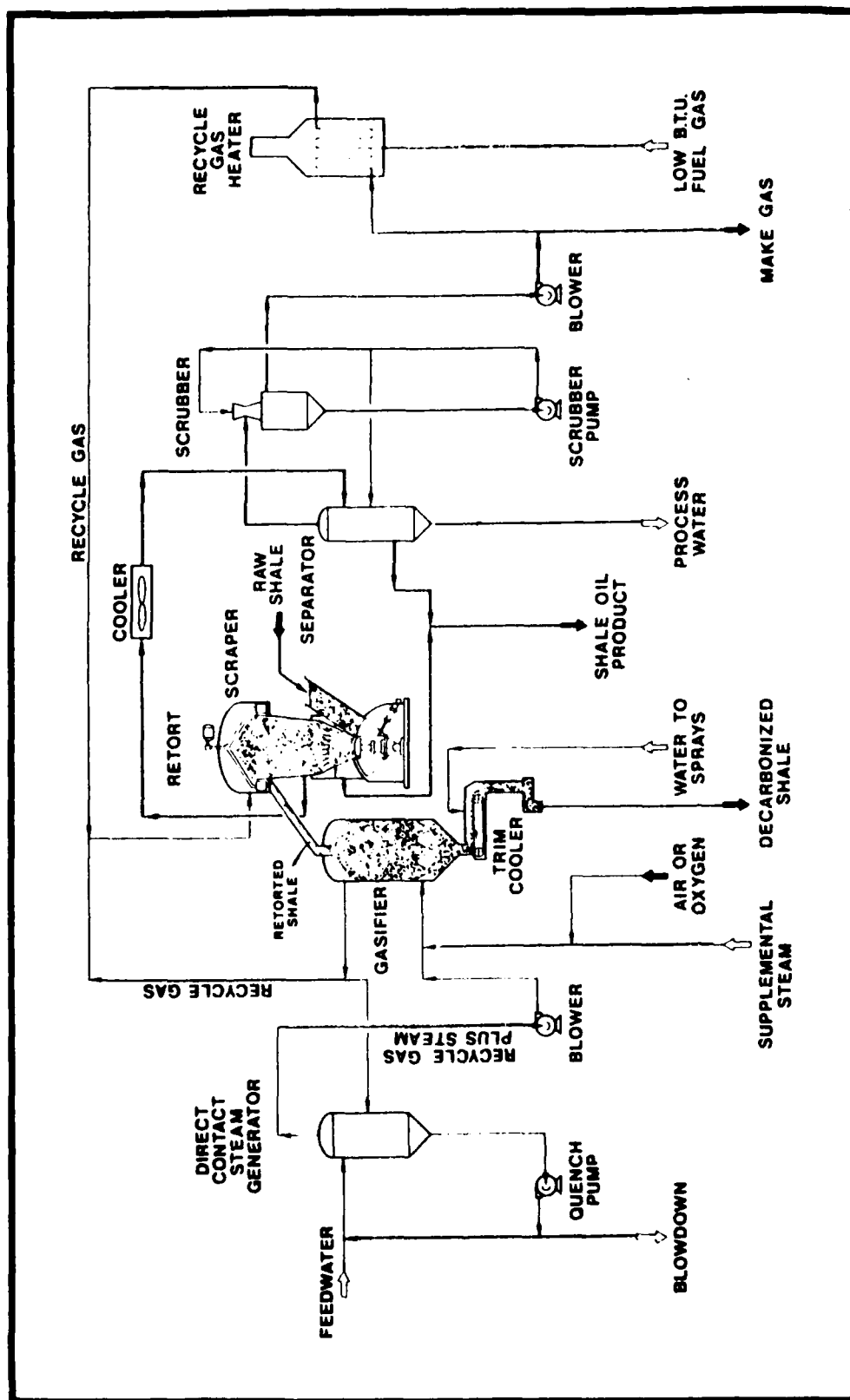FIGURE 6

Union Oil Retort B

FIGURE 7

Union Oil Steam Gas Recirculation (SGR) Retorting Process

pyrolysis. A 3-tpd pilot plant has been operated at Union's California research center.

Union proceeded with plans to design and construct a 1,500-tpd demonstration retort of the SGR design and a prototype rock pump with a nominal capacity of 5,000 tpd. However, in 1975, Union announced that it would bypass the 1,500-tpd demonstration unit and instead build a commercial facility in Colorado with a capacity of 10,000 tpd with production of 7,000 bpd of crude shale oil. This facility was to be of the Retort B design due to the marginal economics of the SGR process as determined by engineering and cost studies. These plans were postponed, however, due to the uncertain political and economic climates present.[14]

In early 1977, Union announced still another process, the SGR-3 process, shown in Figure 8. The SGR-3, a modified Retort B, adds a processing step to utilize the residual carbon on the spent shale.

In early 1978, Union again announced plans to construct a facility in Colorado. However, construction of this facility was contingent upon the creation of the necessary economic climate by the U.S. Congress. Specifically, Union was waiting for a $3/bbl tax credit to be passed. Then, in October 1980, Union announced plans to begin work on a 50,000 bpd facility in the belief that adequate financial assistance could be negotiated with the federal government.[164]

Technology

Retort A, the first oil shale retort developed by Union Oil, is a direct heated retort that utilizes the upward flow of solids and the downward flow of gases, with heat being provided by combustion of the residual carbon remaining on the spent shale following the pyrolysis of the organic fraction. Because the residual carbon on the spent shale is burned, Retort A exhibits a relatively high thermal efficiency of 83%. However, due to nitrogen dilution caused by injecting air into the retort, approximately 40% of the energy produced in Retort A is
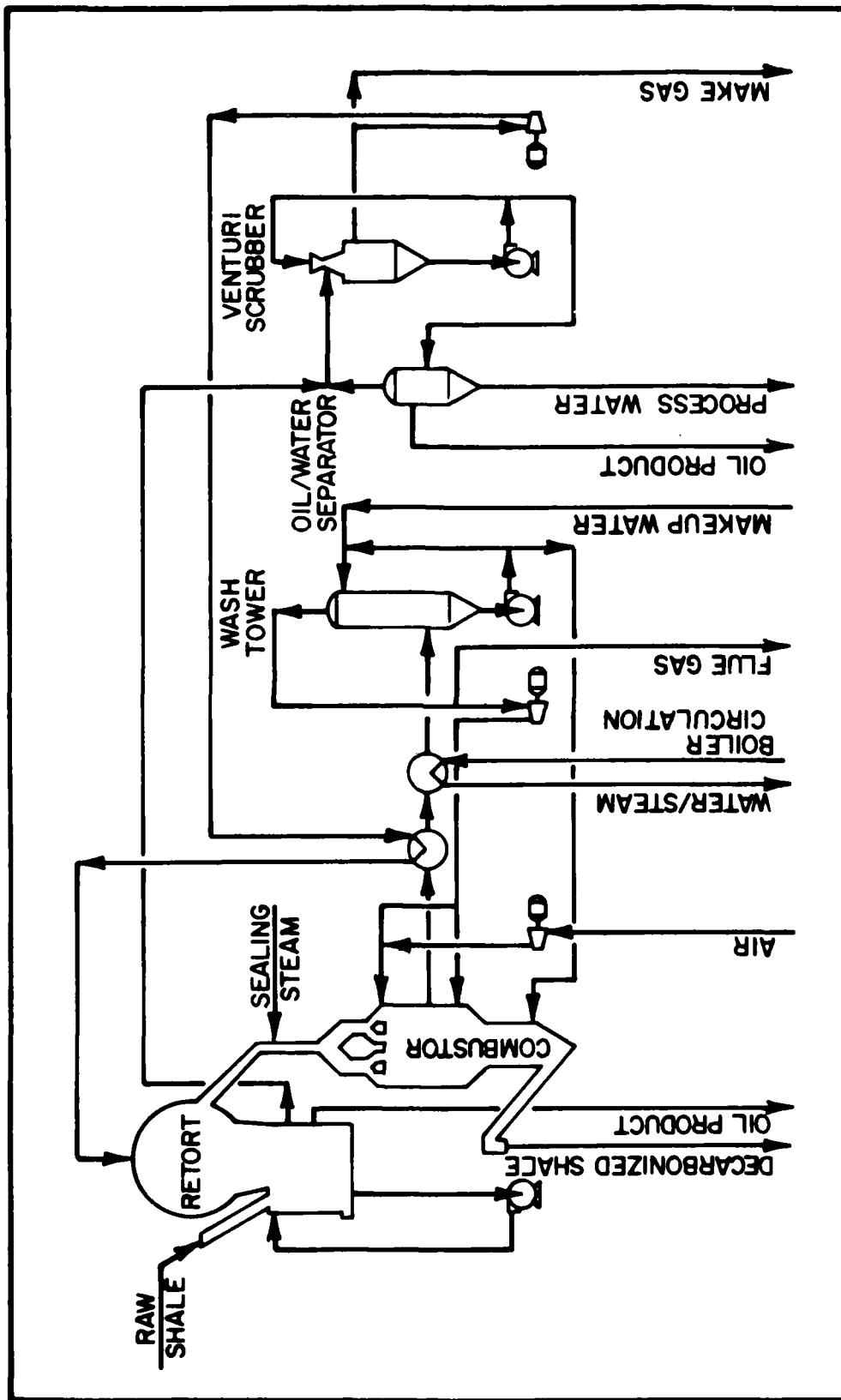
FIGURE 8

Union Oil SGR-3 Retorting Process

contained in the product gas, having a heating value of only 120 Btu/scf. The remaining 60% of the energy produced is contained in the crude shale oil having the properties indicated in Table 4. Based on the Fischer assay, approximately 75% oil recovery is exhibited by Retort A.

TABLE 4

Properties of Crude Shale Oil from Retort A

Gravity, °API	18.6
Carbon, wt %	84.0
Hydrogen, wt %	12.0
Nitrogen, wt %	2.0
Sulfur, wt %	0.9
Oxygen, wt %	0.9
Ash, ppm	NA
Conradson Carbon, wt %	5.6
Flash Point, °F	192 (COC)
Btu/lb	NA
Pour Point, °F	80.0
Viscosity, SUS at 100°F	210.0
Distillation, mod. Engler, °F	
IBP	NA
10	465
50	775
90	NA
EP	NA

Retort B, the second retorting process developed by Union Oil, is the process that will be utilized in commercial retorting plants built by Union Oil. Retort B is an indirect heated process, using recycle gas heated to 950° to 1,000°F in a fired heater to provide the heat for pyrolysis.[144] The process produces high liquid yields and a high-Btu gas product. Liquid product quality is high due to the low temperature, low residence time, and oxygen-free atmosphere during retorting. Some properties of the crude shale oil from Retort B are shown in Table 5. Because the residual carbon on the spent shale is not burned, the 69% thermal efficiency of Retort B is less than that of Retort A.

TABLE 5

Retort B Oil Properties

Gravity, °API	22.2

ASTM, D-1160 Distillation

IBP	150
10	390
30	620
50	770
70	875
90	1,010
Maximum	1,095

Sulfur, wt %	0.8
Nitrogen, wt %	1.8
Oxygen, wt %	0.9
Fischer Water, wt %	0.2
Pour Point	60°F
Arsenic, ppm	17
Conradson Carbon Residue, wt %	2.1
Heating Value, gross, M Btu/gal	142

As shown in Figure 6, crushed and screened oil shale from the feed bin flows through two feed chutes to a solids pump. Shale oil acts as an hydraulic seal to maintain retort pressure and to prevent the escape of product gas from the shale feed chutes.

The solids pump is mounted on a movable carriage completely enclosed within the feeder housing and is immersed in shale oil. The pump consists of two 10-ft-diam piston and cylinder assemblies that alternately feed shale to the retort. While one cylinder is filling with shale during a piston downstroke, the other piston is charging shale to the retort during a piston upstroke. When this operation is completed, the pump carriage is moved horizontally until the full cylinder comes under the center line of the retort. This cylinder charges its shale into the retort, while the other fills with shale from the other feed chute. The carriage is then moved back into its original position, and the cycle is repeated. Seal plates outboard of each cylinder close off the idle feed chute to prevent discharge of shale into the feeder housing. The carriage and solids

pump are hydraulically operated and rest on wheels that run on tracks during horizontal travel.

The shale is retorted as it rises through the retort core by the counter-current flow of hot recycle gas. As the retorted shale rises above the upper core lip, it forms a freestanding pile. A rake rotates just above the surface of the pile to break up any agglomerates that may form and to assist their move-ment down the surface of the pile. The space above the upper cone is enclosed by a dome. The retorted shale slides down chutes and through the cone wall to the retorted shale outlets.

Hot recycle gas is introduced into the space between the dome and the pile of retorted shale. It flows downward into the rising shale to provide the heat necessary for pyrolysis of the kerogen. The kerogen decomposes into liquid and gaseous products. These products flow down the retort into the lower section where a series of vertical slots around the perimeter of the lower cone wall provide the openings for separating the condensed oil and retort vapors from the solids. In the disengaging section surrounding the lower cone, the liquid level is controlled by adjusting the rate at which the oil product is removed and gases are drawn from the space above the liquid level. Shale particles that fall through the slots into the disengaging sections are recycled by screw conveyors into the feed chutes.

The SGR process is a modified Retort A, in which the spent shale is sent to a gasifier to produce synthesis gas for injection into the retort to provide heat for pyrolysis. This process can be operated to produce either a high- or low-Btu product gas depending on whether oxygen or air is used in the gasifier. Oil yield from the SGR process is 100% of Fischer assay with a thermal efficiency of 82%.

The SGR-3 retort is a modified Retort B. In this process, gasification and combustion of the coke are accomplished, and heat from the resulting flue gas is

transferred to a recirculating product gas stream to provide heat for pyrolysis. By utilizing the residual carbon, the SGR-3 process exhibits a thermal efficiency of approximately 83% while maintaining an oil yield of 100% of Fischer assay. The gasification/combustion step used in the SGR-3 can be retrofitted to Retort B so that high thermal efficiencies can also be achieved in that process.

Union cites several advantages, which are summarized here, of using upward solids flow and indirect heating:[144]

- Oil liberated from the shale is forced downward rapidly toward cooler shale by the gas flow. This quenches polymerization reactions that form heavy oil difficult to refine.

- Gravity assists drainage of oil away from the retorting zone and avoids refluxing and coking of the product oil.

- Retorting takes place near the top of the retort where pressure between the shale particles is minimal. Agglomeration and pressure drop buildup can be avoided, and rich shales can be processed.

- The high heat capacity of the gas and high gas/solids heat transfer rates, combined with a positive solids flow, permit operation at exceptionally high mass velocities.

TOSCO II Process

Background

In 1952, the Tosco Corporation (formerly The Oil Shale Corporation) purchased the U.S. patent rights to an oxide reduction process developed by a Swedish inventor and used that process as the basis for the TOSCO II oil shale retort. Beginning in 1955, Tosco began a developmental program that was contracted to the Denver Research Institute (DRI).[10] Several patents were acquired by Tosco as a result of early work by DRI dealing with:

- Counter and parallel flow of heat transfer solids and shale.
- Fluidized bed combustion of spent shale.
- Various retort gas scrubbing processes.
- Ball heating processes.
- Raw oil shale preheating processes.

This work led to the construction of a 24-tpd pilot plant in 1957.

In 1964, Tosco joined with Sohio and Cleveland-Cliffs Iron Company to form the "Oil Shale Venture," later renamed the Colony Development Company. Because of successful operation and favorable economics demonstrated by the pilot plant, Colony constructed a 1,000-tpd semiworks plant in 1965. This plant was located on private property 17 mi north of Parachute, Colorado. Field operation of the semiworks plant continued for 2 yr, and, in 1968, a design study was completed for a 66,000-tpd complex using six 11,000-tpd modules to produce roughly 46,000 bpd of shale oil.

Then, in 1969, Atlantic Richfield joined the Colony Development Company, and a second semiworks program was initiated. This second program was designed to study scale-up procedures and to test environmental protection equipment that was required under the provisions of newly passed federal laws. Also in this year, the name of the Colony Development Company was changed to the Colony Development Operation.

After modification of the semiworks plant to incorporate the new equipment, testing proceeded until April 1972. During this period, approximately 220,000 tons of oil shale, producing 180,000 bbl of crude shale oil, was processed.

In 1974, the cost estimate for the 66,000 tpd commercial facility was updated. Colony subsequently announced a suspension of project activities and cited economic uncertainty and the lack of a federal energy policy.

1974 began a period of reorganization for Colony. As a result of the increased cost estimate and economic uncertainty, Sohio and Cleveland-Cliffs withdraw from the operation. They were replaced by Ashland Oil and Shell Oil. Shell withdrew in 1976, followed by Ashland in 1977. Then, in 1980, Atlantic Richfield's 60% interest in the project was purchased by Exxon Co., U.S.A., leaving the present partners of Exxon and Tosco.

Technology

The TOSCO II retort is an indirectly heated retort in which hot ceramic balls carry heat to finely crushed oil shale. The basic configuration of the process is shown in Figure 9. Raw shale, crushed to minus ½ in., is fed to the retorting train and preheated to about 500°F by direct heat exchange with flue gas from the ball heater. The preheated raw shale is separated from the flue gas in settling chambers and cyclones and sent to a rotating drum retort. The flue gas is incinerated within the preheat system to reduce the amount of trace hydrocarbons in the discharge flue gas.

Pyrolysis is accomplished in the retort by solid-to-solid heat exchange between the preheated shale and hot ceramic balls that enter the pyrolysis drum at about 1,200°F. The balls are heated in a direct fired heater using product gas for fuel. The rotating pyrolysis drum provides intimate contact between the shale and the ceramic balls. Pyrolysis takes place when the shale temperature reaches approximately 900°F. The retort products of balls, spent shale, and hydrocarbon vapors pass from the pyrolysis drum to a separation vessel. The hydrocarbon vapors are sent to further processing, which will be discussed later. The ceramic balls and spent shale pass over a rotating screen called a trommel. The shale, which has been thoroughly crushed during retorting, falls through holes in the trommel and passes to a retorting drum steam generator where it is cooled to about 300°F. The cooled shale is then moistened to approximately 14% and sent to disposal.

The ceramic balls pass over the trommel and fall to a vessel where dust is removed from the surface. The dust-free balls are then circulated back to the ball heater by means of a bucket elevator.

Crude shale oil from the TOSCO II process exhibits the properties shown in Table 6. As with other crude shale oils, this oil contains a significantly higher amount of nitrogen than conventional petroleum crudes to. It is worth
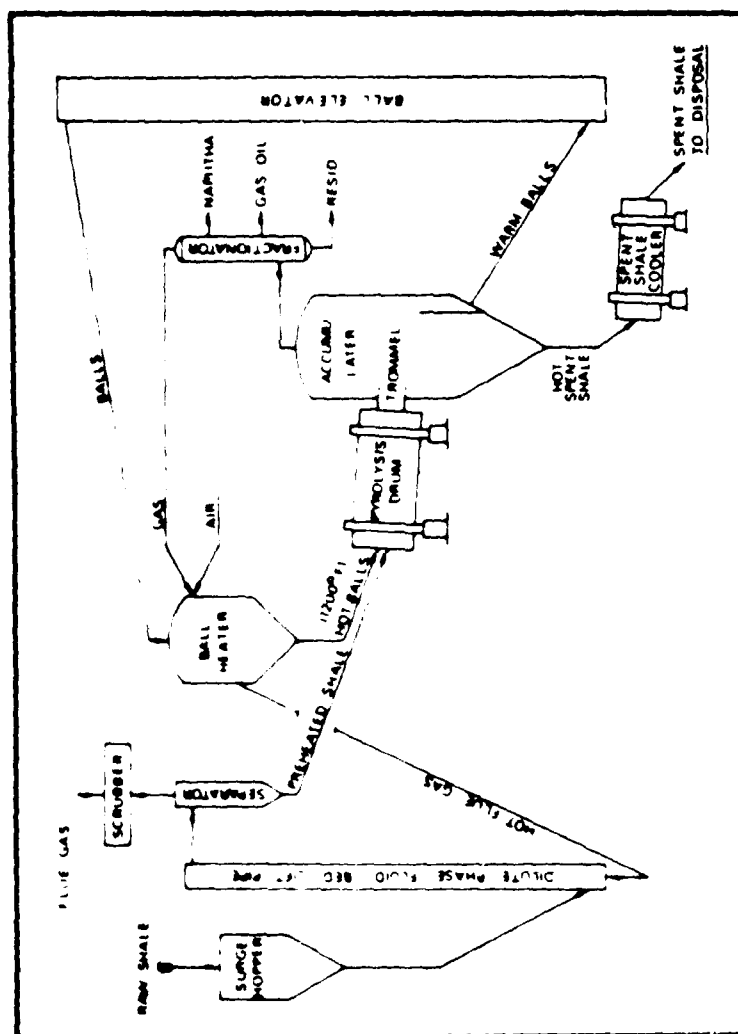
FIGURE 9

TOSCO II Retorting Process

noting that the Final Environmental Impact Statement for the Colony Development
Operation describes a plan to include shale oil upgrading facilities as part of
the retorting plant site. Included in the upgrading scheme are fractionation,
hydrogenation, sulfur recovery, and ammonia recovery units. As a result, the
pipeline product from the Colony plant will be a high-quality syncrude, low in
nitrogen and with a significantly improved boiling range. However, the processes
used to convert the crude TOSCO II shale oil to this upgraded product fall in the
realm of advanced state-of-the-art refining processes. As such, a detailed dis-
cussion of the upgrading techniques to be employed by the Colony Development
Operation will be deferred to the section of this report dealing with shale oil
refining.

TABLE 6

Inspection Data for Tosco II Crude Shale Oil

Gravity, °API	21.2
Pour Point, °F	25[1]
Nitrogen, wt %	1.9
Oxygen, wt %	0.8
Sulfur, wt %	0.9
Carbon, wt %	85.1
Hydrogen, wt %	21.6
Viscosity, SUS	
100°F	106
212°F	39
Distillation:	
5 vol % at	200°F
10 vol % at	275
20 vol % at	410
30 vol % at	500
40 vol % at	620
60 vol % at	775
70 vol % at	850
80 vol % at	920
90 vol % at	--

[1] The 25°F pour point is for oil that has been
"heat treated" as per conditions described by
U.S. Patent No. 3,284,336.

In general, oil yields from a TOSCO II retort are quite high, consistently
producing over 100% of Fischer assay. However, because the energy in the spent

shale carbon is not utilized, thermal efficiencies are low. A significant por-
tion of the product gas is burned in the ball heater. The low energy efficiency
could be improved if Tosco develops, to a practical point, the processes it has
patented to burn or gasify the retorted shale, providing fuel for the ball
heater.

Superior Oil Process

Background

The Superior Oil Company has significant land holdings on the northern edge
of the Piceance Creek Basin in Colorado. The oil shale in this area contains
nodules of nahcolite (naturally occurring sodium bicarbonate) and significant
quantities of dawsonite, which can be decomposed to yield alumina and soda ash.
Because each of these products has a market, Superior developed its retorting
technology around the recovery of dawsonite and nahcolite as well as oil.

Superior's process utilizes a traveling grate enclosed in a large, circu-
lar tunnel, depicted in Figure 10. A similar traveling grate process has been
used for many years to sinter iron ore fines and to roast lead and zinc oxide
ores. This technology was selected by Superior because of its proven operabil-
ity and because it allows for good temperature control. A high degree of tem-
perature control is essential to Superior's operation, as excessively high tem-
peratures can introduce complications to the recovery of alumina.

Although extensive research and development programs were conducted by
Superior prior to 1972, not until then did they announce intentions to design and
construct processing facilities to recover shale oil, nahcolite, alumina, and
soda ash. At that time, plans called for the construction of a small-scale pilot
plant, followed by a 6,000-bpd operation, and finally, for the building of a
50,000-bpd multimineral processing plant.

Since 1972, Superior has been involved with the development of individual
recovery processes for each of the products. A small pilot plant has been

COOL RECYCLE GAS

CARBON RECOVERY

COOL RECYCLE GAS

SHALE HEATING

HOT RECYCLE GAS

SHALE FEED

SHALE COOLING

SHALE DISCHARGE

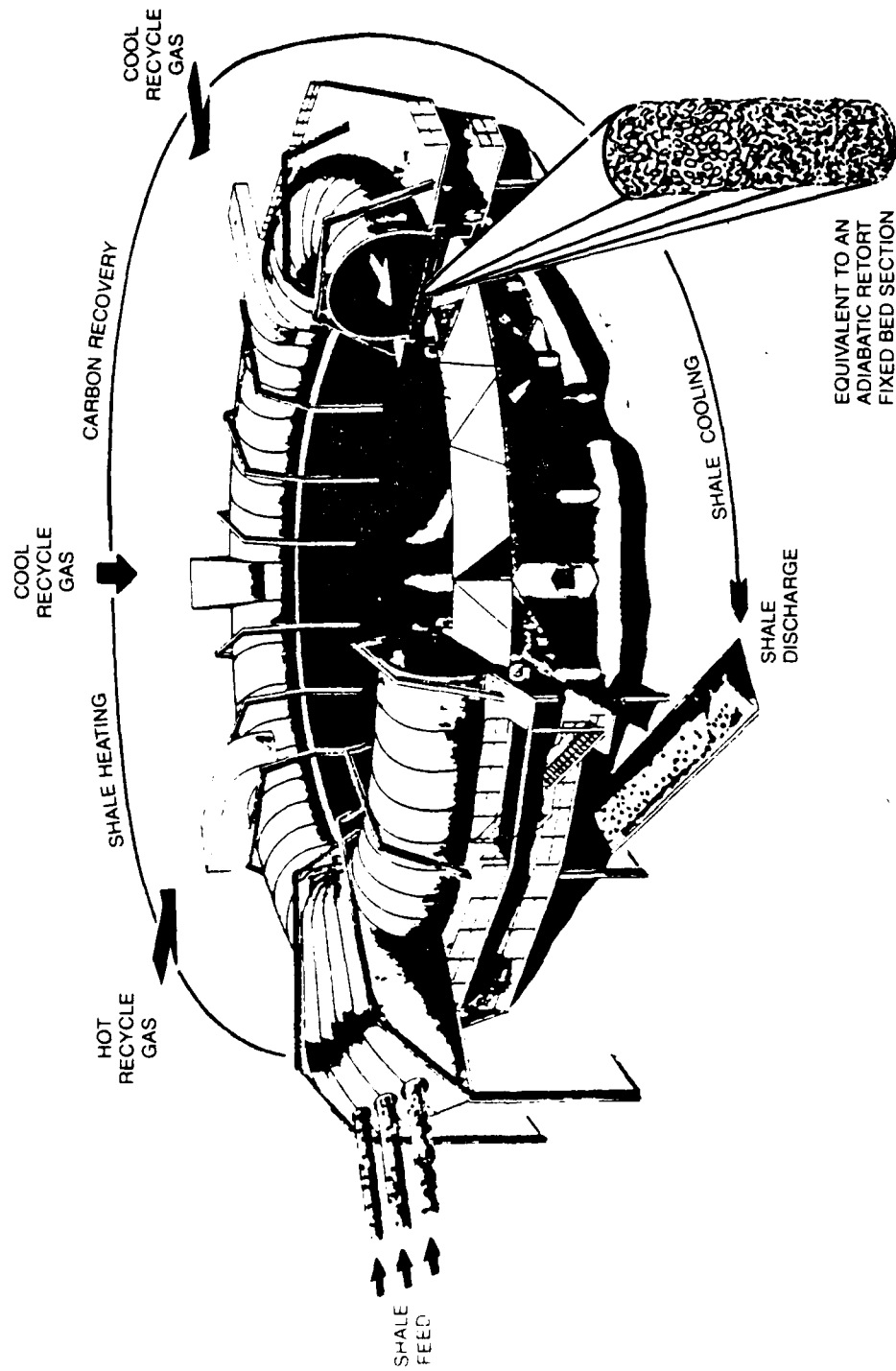EQUIVALENT TO AN ADIABATIC RETORT FIXED BED SECTION

FIGURE 10

Conceptual View of Superior Retort

operated in Denver, Colorado, and, in 1977, a 250-tpd pilot plant was brought on stream in Cleveland, Ohio.

Commercial development of Superior's process was held up pending a Bureau of Land Management (BLM) decision on a proposed land exchange. Superior's land holdings were not in a configuration that favored large-scale development. As a result, in 1974, Superior requested a land exchange with the U.S. Department of the Interior, Bureau of Land Management. The proposed exchange would have allowed Superior to exchange 2,572 acres of its land for 2,045 acres of BLM land. The exchange, if approved, would have provided Superior with a section of land that was more amenable to commercial development. Approval of the proposed exchange was delayed and by BLM review and by the preparation of an Environmental Impact Statement. Then, in February 1980, BLM denied the exchange citing unequal value of the two tracts of land involved.

In November 1980, Superior announced land interest trades that would permit it to accelerate the development of a commercial oil shale facility. Superior's partners in this venture are the Standard Oil Co. of Ohio (Sohio) and Cleveland-Cliffs Iron Co. The project site is on private land owned by the developers in the southern part of the Piceance Creek Basin.

Technology

The retort that The Superior Oil Company proposes to use in its multimineral processing plant is a circular traveling grate, a cross-sectional view of which is shown in Figure 11. In this process, a layer of shale that has been crushed and screened to between ¼ and 4 in. is placed in a continuous grate. The grate is designed so that gases can flow through it and the shale bed. As the shale is carried through the retort by the grate, it passes through several zones in which it is heated, retorted, cooled, and dumped.

The shale can be heated by either of two methods in the Superior retort. In the so-called "direct heated" mode shown in Figure 12, part of the retort gas is
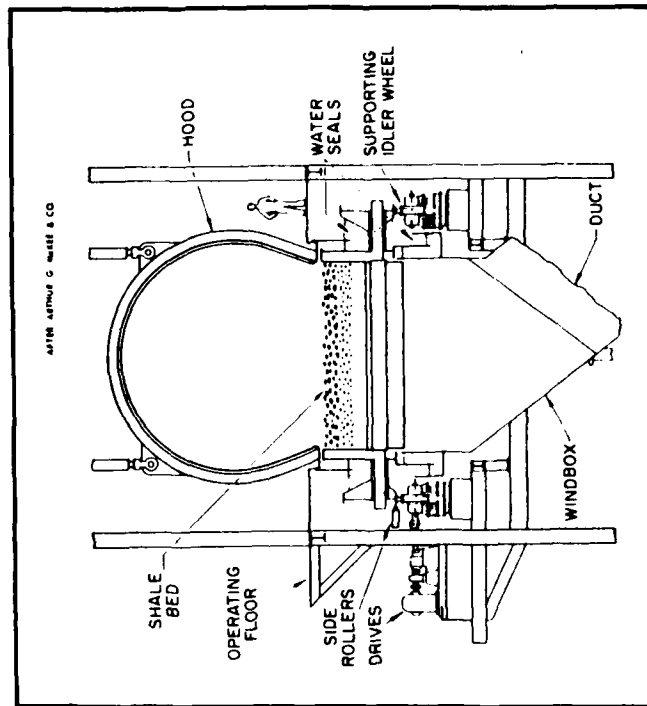
FIGURE 11

Cross Sectional View of Superior Retort

burned, and the flue gas produced is mixed with preheated recycle gas from the shale cooling zone.[80] The resulting combination of gases produces heating zone inlet temperatures as desired between 1,100° and 1,500°F. The heating value of the product gas is 90 to 150 Btu/SCF, depending upon shale grade.

In the so-called "indirect heated" mode, shown in Figure 13, part of the retort gas is burned with preheated air in a tubular furnace to heat recycle gas to the desired temperature for introduction into the heating zone.[80] Carbon recovery is achieved by controlled oxidation with either preheated air or oxygen. Oxygen is used when a higher heating value gas is desired since nitrogen dilution is avoided.

The crude oil produced from the Superior retort has the properties shown in Table 7.[161]

TABLE 7

Physical Properties of Superior Crude Shale Oil

Gravity, °API	18-25
Viscosity, SUS at 100°F	100-200
Pour Point, °F	70-90
Nitrogen, wt %	1.8-2.1
Sulfur, wt %	0.7-0.9

The Superior retort is capable of producing this oil at a yield of more than 99% of Fischer assay[80, 161] and, because some of the residual carbon is burned, the retort exhibits reasonable thermal efficiencies, in both the direct and indirect heated modes.

Obviously, the most significant advantage that the Superior retort has is that it allows more than one product to be recovered from the available resource. In addition, the Superior retort can be used to process softer shales such as those found in Australia. These soft shales are more difficult to process in other retorts because of clinkering and plugging. Superior also cites the proven reliability of the basic process as a significant advantage.
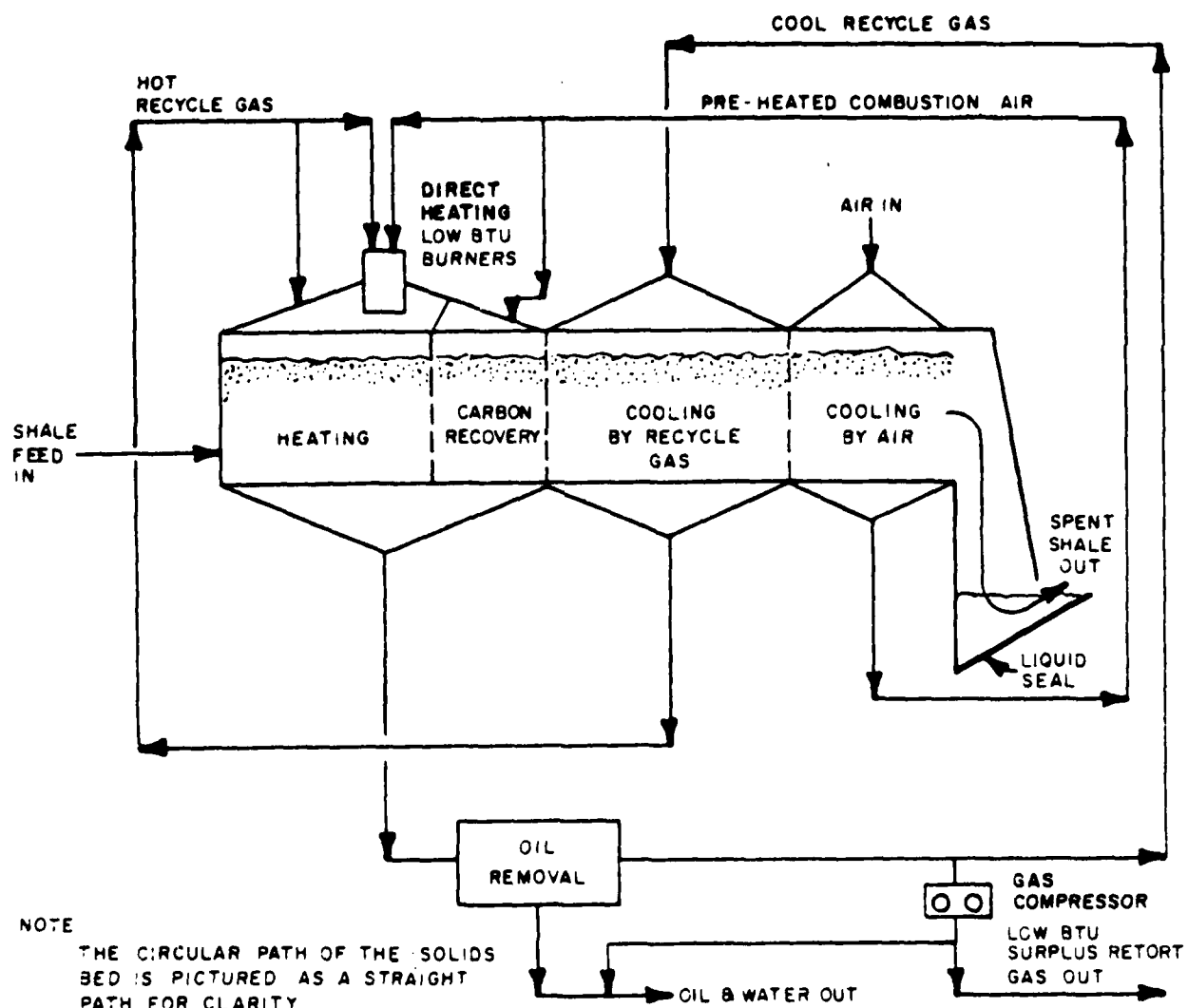
FIGURE 12

Simplified Process Flow Diagram for
Commercial Circular Grate Retort: on Direct Heated Mode

Lurgi-Ruhrgas Process

Background

Lurgi was among the first engineering companies to be involved with the pyrolysis of oil shale. In the period between 1938 and 1942, Lurgi built two tunnel kilns that were used to process 800 tpd of oil shale in northern Germany.[132] After 1942, four more of these kilns were built by Lurgi to process Estonian shale. However, only two of these ever came on line.

In the years that followed, Lurgi developed, in conjunction with other firms, a number of processes that were used to process coal and oil shale. Among these were a low-temperature carbonization process (the Lurgi-Spühlgas kiln), a batch process used to retort moderately sized lumps of oil shale (the Lurgi-Schweitzer process), a continuous process that utilized an inclined oscillating grate (Hulofen), an in situ process, and a process that retorted oil shale in piles.[161]

In the 1950's, Lurgi was involved with the development of a fluid bed retorting process called the Rohrbach-Lurgi process. In addition to recovering energy in the form of shale oil, this process burned the residual carbon on the shale to generate steam and electric power. In 1960, two plants using this process were built in Dottenhausen, West Germany. These plants were capable of processing 720 tpd of raw shale feed and of generating 6,000 kw of power. These two plants are still in operation.[132]

Also in the 1950's, Lurgi and Ruhrgas AG developed a process for the devolatilization of coal fines to produce a high-Btu gas. The heat carriers for the process were pebbles and Mullit balls, and the residual coke fines from the process were fired in a steam boiler. Primarily due to the unfavorable economics of using the balls as heat carriers, the process was modified to use the fine-grained char instead. This modified process was tested for several years in 5- to 10-tpd pilot plants, being used primarily for the devolatilization and

gasification of various coals and also for cracking heavy-liquid hydrocarbons to produce olefins and town gas. The process was applied commercially in many countries.[132]

To demonstrate the applicability of the Lurgi-Ruhrgas process for oil shale, Lurgi conducted a number of pilot-plant tests. In 1967, tests were conducted involving the retorting of about 50 tons of Colorado oil shale over a 1-wk period and, in 1968, a second set of tests was performed in which about 240 tons of Colorado shale were retorted over a 3-wk period. The shales had Fischer ,ɔ of 27 to 33 gpt, and recovery during the runs was over 100% of Fischer assay.[161]

Technology

The Lurgi-Ruhrgas retorting process, shown schematically in Figure 14 utilizes solid heat carriers to provide the necessary heat for pyrolysis.[161] Raw oil shale, crushed to approximately minus ¼ in., is fed to the screw mixer where it is mixed with six to eight times that quantity of hot solids from the collection bin. The temperature of the raw shale increases to about 500°C within a few seconds, effectively pyrolyzing the organic matter in the shale. The hot spent shale exits the screw mixer and falls to the lower section of the lift pipe where it contacts combustion air that has been preheated to about 450°C in the waste heat recovery portion of the process. The solids are lifted up the lift pipe by the combustion air while, at the same time, the carbon residue is burned off the spent shale. The gas/solid mixture separates in the collection bin after having reached a temperature of about 650°C. The heated solids are then mixed with incoming raw shale, and the cycle continues. Excess solids are removed from the system after having been burned in the lift pipe. In this way, all of the fuel available in the raw shale is either produced as product oil or is used in the process, as is the case with the residual carbon.

The off gas from the collection bin passes through a series of dedusting and waste heat recovery units in which the energy contained in the hot gas is
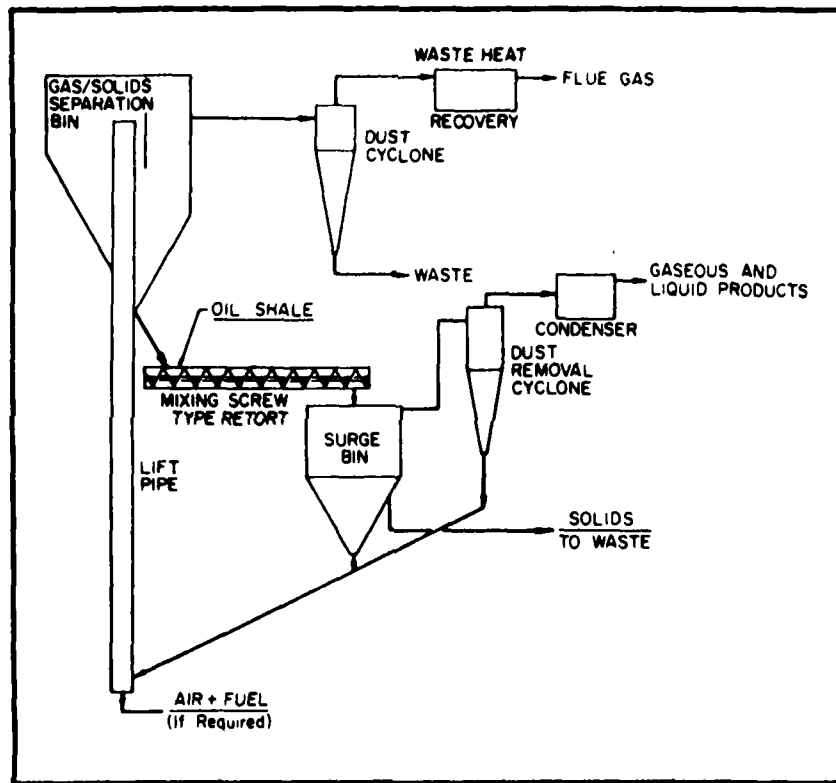
FIGURE 14

Lurgi-Ruhrgas Retorting Process

used to generate steam and to provide the heat necessary to raise the temperature of the combustion air entering the lift pipe to 450°C. Any solids removed from the off-gas stream are combined with the spent shale stream from the collection bin and are sent to a mixer to be moistened with water before disposal.

The dust-laden hydrocarbon vapors from the screw mixer are sent to a pair of series-connected cyclones where most of the dust is removed and then returned to the circulating solids stream. The vapors are then sent to a series of three scrubbing coolers in which the oil vapors are condensed in stages to form three liquid products: heavy oil, middle oil, and gas naphtha. The properties of these three oil products are given in Table 8.[10,132]

Oil recovery from the Lurgi-Ruhrgas process is very high, consistently exceeding 100% of Fischer assay. In addition, the thermal efficiency of the process is high, as all residual carbon and oil remaining on the shale is burned and the resulting heat is utilized in the process.

TABLE 8

Shale Oil Analysis from Lurgi-Ruhrgas Process

	Heavy Oil	Middle Oil	Gas Naphtha
Yield, vol %	21.0	67.0	12.0
Gravity, °API	16.5	41.9	70.9
Viscosity at 50°C, cP	98.0	1.25	NA
Ultimate Analysis			
C, wt %	85.6	85.5	84.2
H, wt %	10.7	12.5	13.2
S, wt %	1.0	0.7	NA
N, wt %	1.5	0.5	NA
O (balance), %	1.2	0.8	NA

Modified In Situ Processes

There are currently two projects in the United States using modified in situ (MIS) technology to recover oil from oil shale. Because the MIS technologies being used at federal lease tracts C-a and C-b are distinct, descriptions of each are presented.

Occidental Petroleum Corporation (Oxy) has developed an MIS technique that is currently being used at Tract C-b. Briefly, the Oxy process involves mining approximately 20% of the retort volume to form a cavern at the bottom of the retort. The remaining 80% of the shale is then explosively rubblized, filling the retort with broken shale and distributing the 20% void space over the entire volume of the retort. To retort the shale, a small amount of outside fuel is ignited at the top of the rubblized shale to heat it to about 900°F. After a specified amount of shale has been heated, the burners are removed, and combustion is continued by injecting air into the top of the retort and burning the carbon residue left on the shale after it has been retorted. This process is similar to direct heated surface retorts, such as the Paraho process, except that the shale bed is fixed, and the combustion zone moves. The combustion zone advances down the retort preceded by the retorting zone in which kerogen is pyrolyzed. The resulting hydrocarbon vapors also move down the retort, condense when they contact as yet unheated shale, and the resulting liquid flows down the retort to a sump from which the oil is pumped to storage.[10] The sequence of mining, blasting, and retorting is shown in Figure 15.

Oxy's field test program began in 1972 on its D.A. shale property located at Logan Wash at the southern edge of the Piceance Creek Basin. Six retorts were rubblized and burned, with approximately 94,500 bbl of shale oil produced. A summary of the size and oil yield of each of the six retorts is presented as Table 9.[107] Parameters that were studied in these field tests include the effect of void volume changes, blast pattern, and retort height and cross-section.[10]
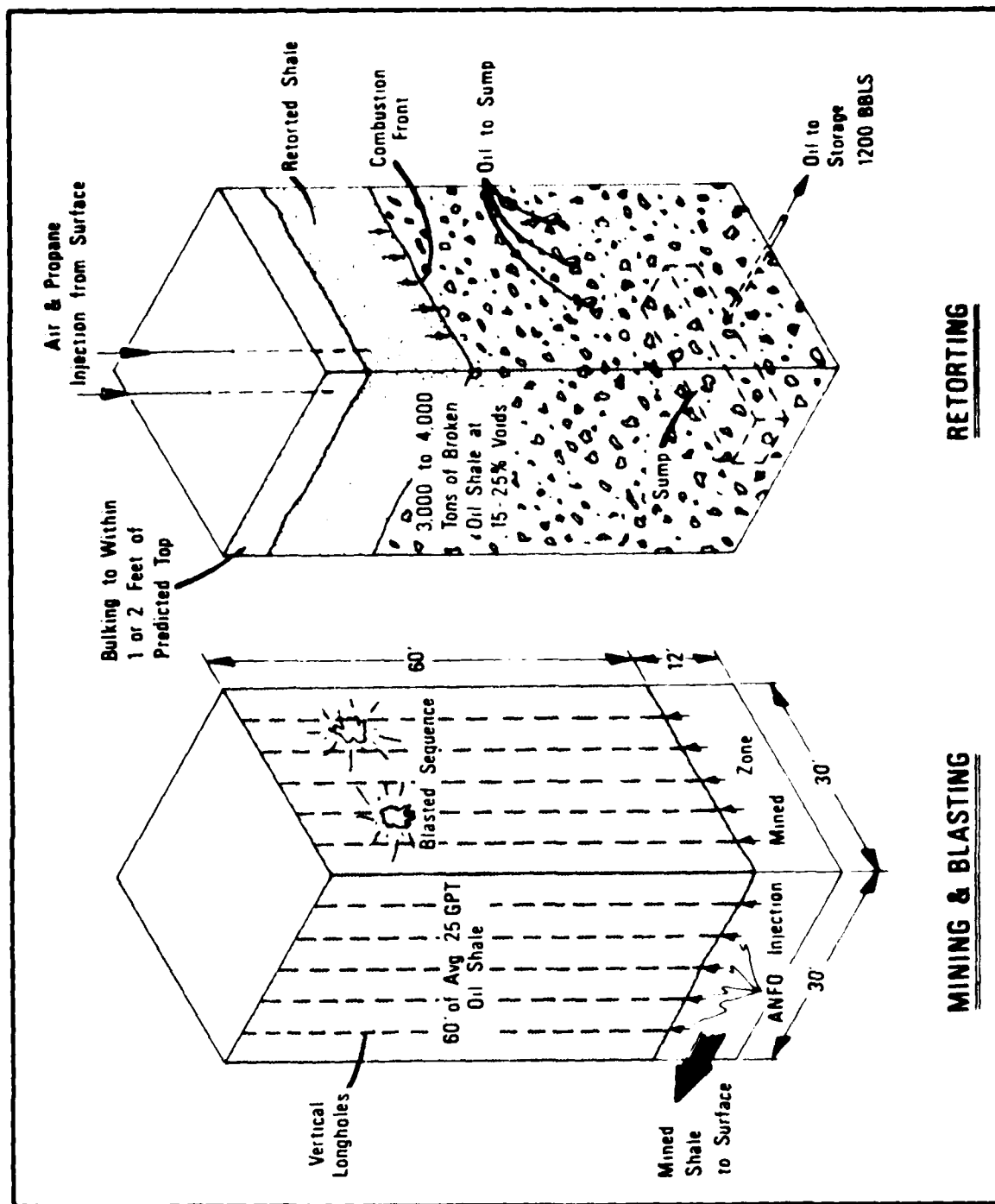
FIGURE 15

Occidental's Modified In Situ (MIS) Recovery Process

TABLE 9

Occidential In Situ Retorting Experiments

(As of July 1979)

Retort	Size ft	Oil Yield bbl
1E	31 x 31 x 72	1,200
2E	32 x 32 x 94	1,400
3E	32 x 32 x 113	1,600
4	120 x 120 x 257	32,000
5	118 x 118 x 167	11,300
6	162 x 162 x 269	47,000

In November 1976, Occidental entered into an agreement with Ashland Oil whereby Oxy gained a 75% interest in Federal Lease Tract C-b in exchange for the use of its MIS retorting technology on the tract site. Two years later, in 1978, Ashland withdrew from the operation at C-b, leaving Oxy in full control. Then in 1979, Tenneco Oil Co. purchased a half interest in the lease for $110 million.

Oil produced from the Oxy MIS process exhibits the properties shown in Table 10.[10] In general, it is a lighter oil with slightly less nitrogen and about the same amount of sulfur as crude shale oil from surface retorts. However, the yield from Oxy's MIS retorts is substantially less than that of surface retorts. The most favorable yield figures have been only about 60% of Fischer assay versus 90% to 100% or more for surface retorts.[96] The trade-off lies in the fact that although the yield from Oxy's MIS retorts is lower than that from surface retorts, Oxy does not require a large capital investment in the form of surface facilities. For example, although some surface retorting of shale will take place and equipment will have to be purchased for this purpose, Oxy will not have to acquire as much equipment, as it will be processing a significantly smaller amount of shale on the surface. This reduced capital investment makes it possible for Oxy to operate profitably with a reduced oil yield from the MIS retorts.

TABLE 10

Properties of Shale Oil from Occidental In Situ Process

Gravity, °API	25
Pour Point, °F	70
Viscosity, SUS at 100°F	70
Nitrogen, wt %	1.5
Sulfur, wt %	0.71
Carbon, wt %	84.86
Hydrogen, wt %	11.80

The second oil shale project utilizing MIS retorting technology is being conducted at Federal Lease Tract C-a by the Rio Blanco Oil Shale Company, a general partnership of Gulf Oil Corporation and Standard Oil Company of Indiana (Amoco). Rio Blanco had first intended to develop Tract C-a using surface technology, but economics dictated that the tract be developed using a MIS approach. The method selected was the Rubble In Situ Extraction (RISE) method developed by Lawrence Livermore Laboratories.

In the RISE method, a portion of the oil shale is removed by underground mining, and the remainder is rubblized and retorted in place. The rubble is created by a continuous mining process, using a modified sublevel caving method, with removal of approximately 20% of the oil shale.[16] Retorting is performed by the same technique employed in the Oxy MIS retort.

Although the RISE method was originally proposed for use by Rio Blanco on Tract C-a, it is currently developing the tract using its own process, which has benefited from technical information acquired under a leasing arrangement with Oxy. In the revised process, approximately 40% of the shale is mined out, and the remainder of the retort is blasted sequentially at different layers. Each layer falls to the bottom of the retort before the next higher level is blasted. By using this technique, Rio Blanco hopes to obtain uniform size distribution in the rubble, an essential part of efficient MIS retorting.[141]

Rio Blanco's first test retort, Retort 0, is about 30 ft on a side and 166 ft tall. It was ignited on October 13, 1980, and is expected to burn for about

9 wk before retorting is completed. For this reason, figures are not yet available concerning the quality of the shale oil product. However, because the retorting procedure itself is similar to that used by Oxy, the oil product will likely exhibit properties similar to oil from the Oxy MIS process (see Table 10).

Other Processes

The previous sections presented detailed descriptions of the six retorting processes that are the closest to being used commercially in the United States. However, there are other processes that either are not at the same level of development or are being used in countries other than the United States. Brief descriptions of these other processes are presented in the following section.

The Nevada-Texas-Utah (NTU) retort is a batch unit utilizing combustion of the carbon residue on the shale to provide heat for retorting. The unit was developed and tested for oil shale processing by the NTU Co. in 1925. Subsequent testing by USBM took place from 1925 to 1929 and again from 1944 to 1951.[10, 141] More recently, 10-ton and 150-ton NTU retorts have been used at the Laramie Energy Technology Center in Laramie, Wyoming, to investigate many of the parameters associated with in situ retorting.

The series of events that occur in the NTU retort are depicted in Figure 16.[139] Shale is charged to the retorting vessel from the top, and the vessel is sealed. A gas burner is used to ignite the top layer of shale in the retort, and air is blown into the retort at the top to support combustion. Once the shale is burning, the gas burner is shut off. Air flow continues through the retort to provide oxygen for combustion and to sweep the oil mist that is produced. The hot gases serve to preheat the cool shale in the bottom of the retort. Pyrolysis of the kerogen occurs in the zone just ahead of the combustion zone which residual carbon on the shale is burned. Recovery of oil from the NTU retort ranges from 60% to 90% of Fischer assay. However, the high labor costs associated with this batch unit make it unsuitable for commercial
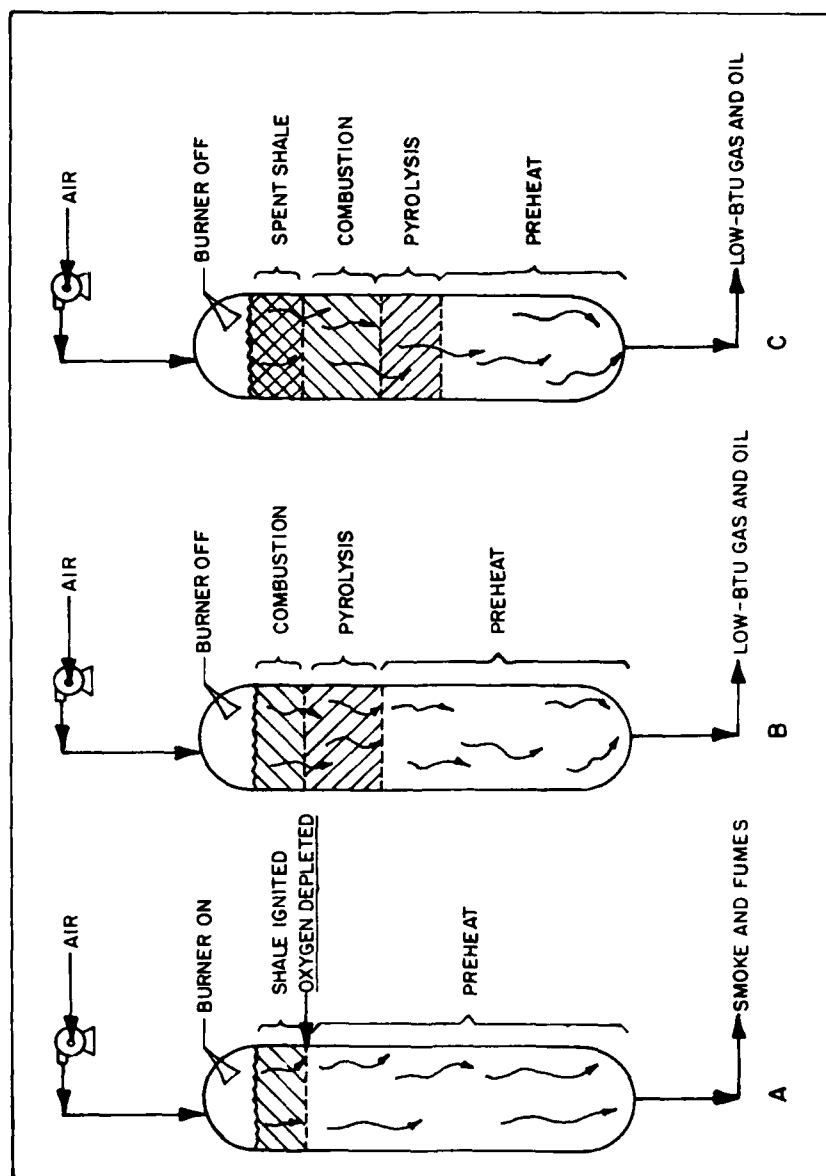
FIGURE 16

NTU Retorting Process

application. In addition, over 600 150-ton retorts would be required to produce 50,000 bpd of crude shale oil.[141]

In 1949, a design and construction effort was initiated to construct a retort that would incorporate all of the parameters thought to be necessary for a successful retorting unit. These parameters were:

- Direct heat transfer from a gas stream to a bed of crushed shale.

- Gravity flow of shale through the retort.

- Internal combustion of residual carbon to provide the heat necessary for retorting.

The resulting design, construction, and revision effort led to the construction of the first Gas Combustion retort. Further revisons led to the development of a more refined unit with the configuration shown in Figure 17.[10] Testing continued from 1949 to 1955 and again from 1961 to 1967. Many variables were tested during these periods, and the results were encouraging enough that the Paraho process was designed based on the work conducted with the Gas Combustion retort.[141]

The Gas Combustion retort operates in the same manner as the Paraho direct heated retort described above. A typical temperature profile for the Gas Combustion retort is shown in Figure 17.

Two retorting processes have been developed jointly with each other in the Soviet Union. These are the Kiviter process, shown in Figure 18, and the Galoter process, shown in Figure 19.[10] The Kiviter process is a vertical kiln retort in which crosscurrent and countercurrent flowing hot gases provide heat for a downward-flowing bed of shale. The hot gases are a combination of directly injected recycle gas in one stream and burned recycle gas in another stream. The Kiviter process is designed to retort shale in the size range of 1 to 5 in. and is said to recover 75% to 80% of Fischer assay as an oil with the properties
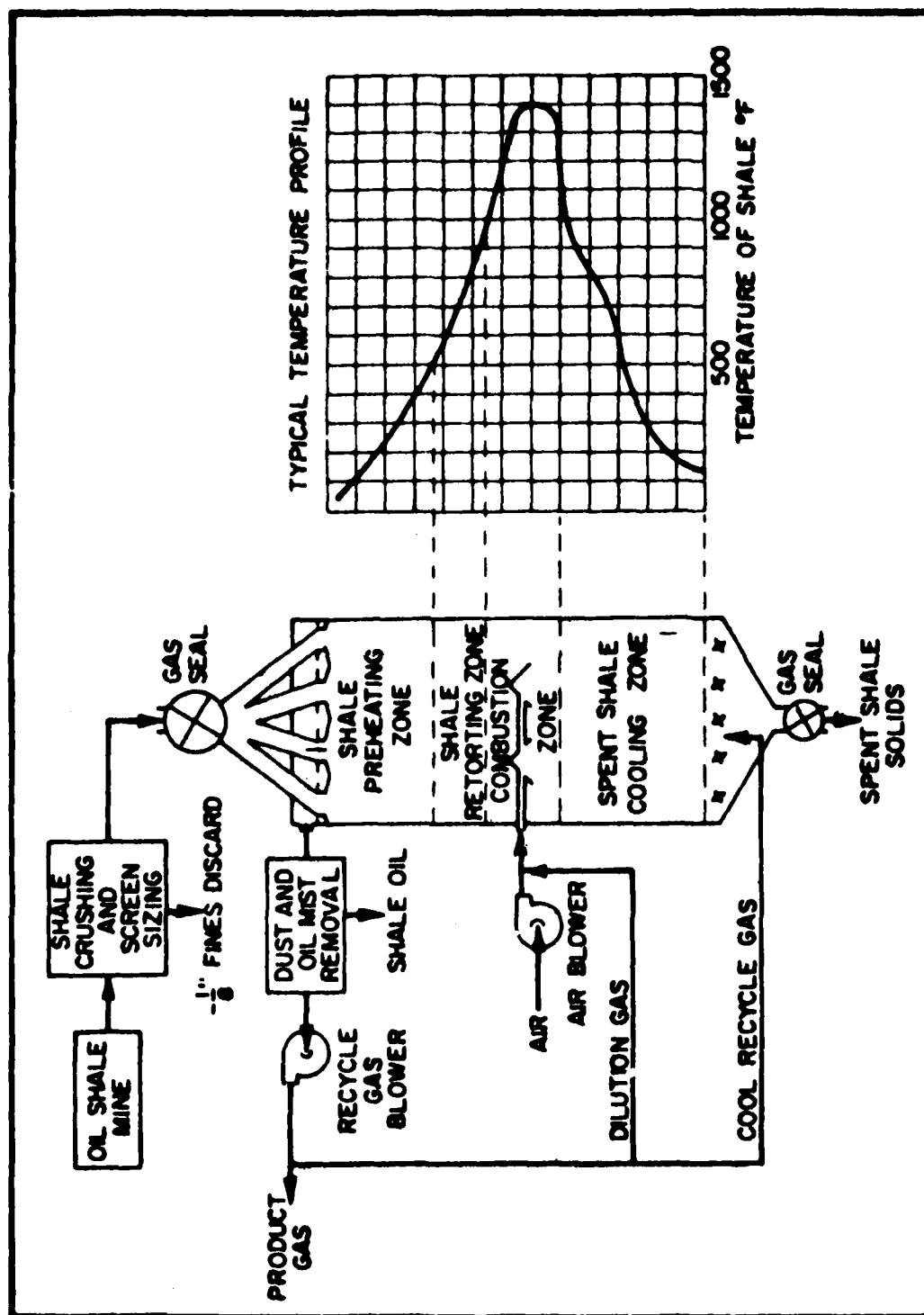
FIGURE 17

Gas Combustion Retorting Process and Temperature Profile
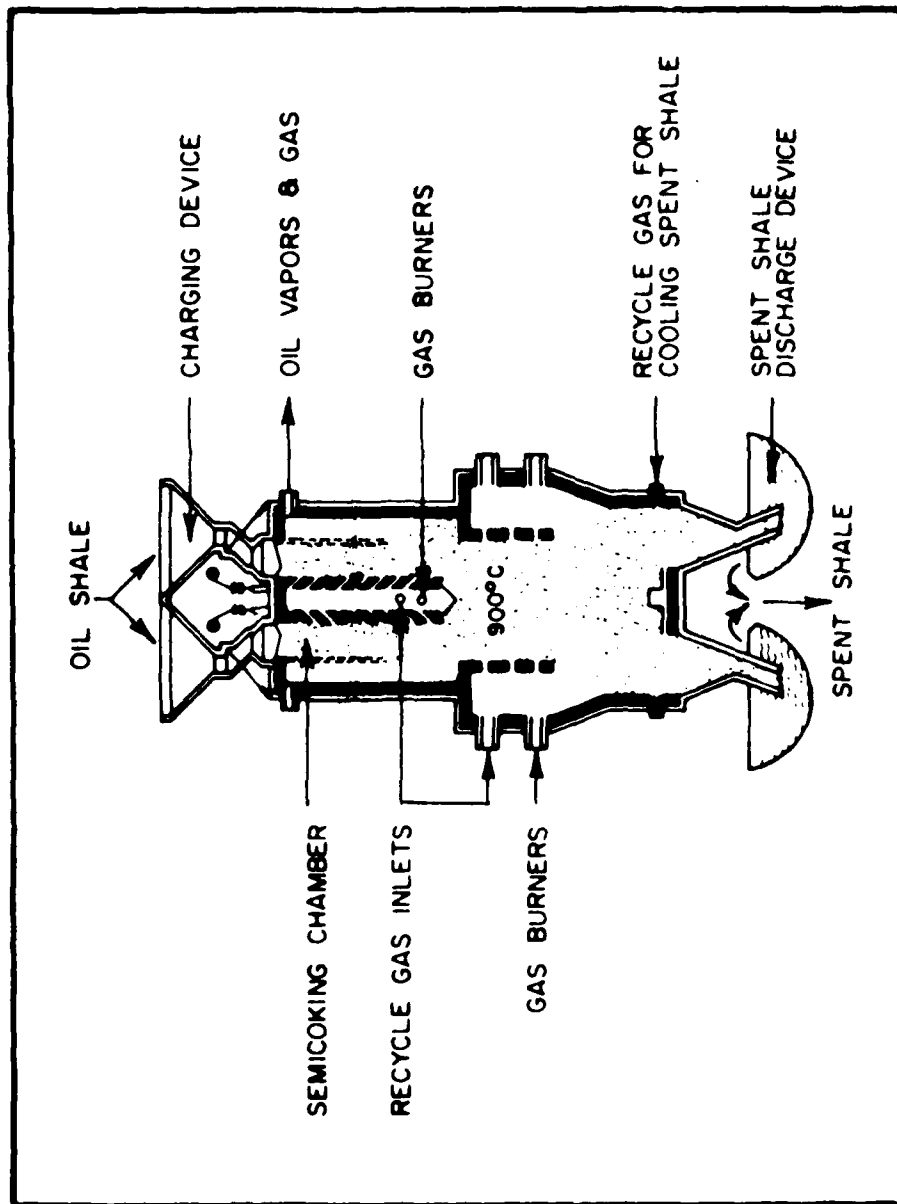
FIGURE 18

Kiviter Retorting Process

indicated in Table 11. The oil described in this table is from a 40-gpt Baltic

shale that varies significantly from U.S. oil shales.

TABLE 11

Typical Properties of Crude Shale Oil Produced in
Kiviter Retort
(Baltic Shale Feed)

Density at 68°F, g/cm^3	1.01
Viscosity at 167 ft, Engler	4.5
Pour Point, °F	5
Coking Value, %	8
Phenols, wt %	2.8
Calorific Value, Gross, Btu/lb	17,100
Distillation, vol %	
Initial B.P., °C	190
200°C	1
250°C	6
300°C	21
360°C	45
Elemental Composition (dry basis):	
Carbon	83.3
Hydrogen	10.0
Sulfur	0.7
Oxygen plus Nitrogen	6.0
	100.0

The Galoter process is an indirect heated process resembling both the TOSCO

II and the Lurgi-Ruhrgas processes. The Galoter process complements the Kiviter

process in that it processes shale less than 1 in. in size. Dried raw oil shale

is mixed with the hot spent shale heat carrier and is sent to a rotating reactor

where the temperature of the raw shale is increased to approximately 960°F. The

kerogen is pyrolyzed, and the oil vapors are carried to a condenser. The hot

spent shale goes to an air-blown fire box similar to the lift pipe of the Lurgi-

Ruhrgas process. In this fire box, the carbon is burned off the shale to recover

the energy available. A portion of the resulting char is used to heat incoming

raw shale, and the rest is sent to a waste heat recovery process. The Galoter

process reportedly recovers 85% to 90% of Fischer assay from the same Baltic

shale used in the Kiviter process. The properties of this oil are shown in Table

12.
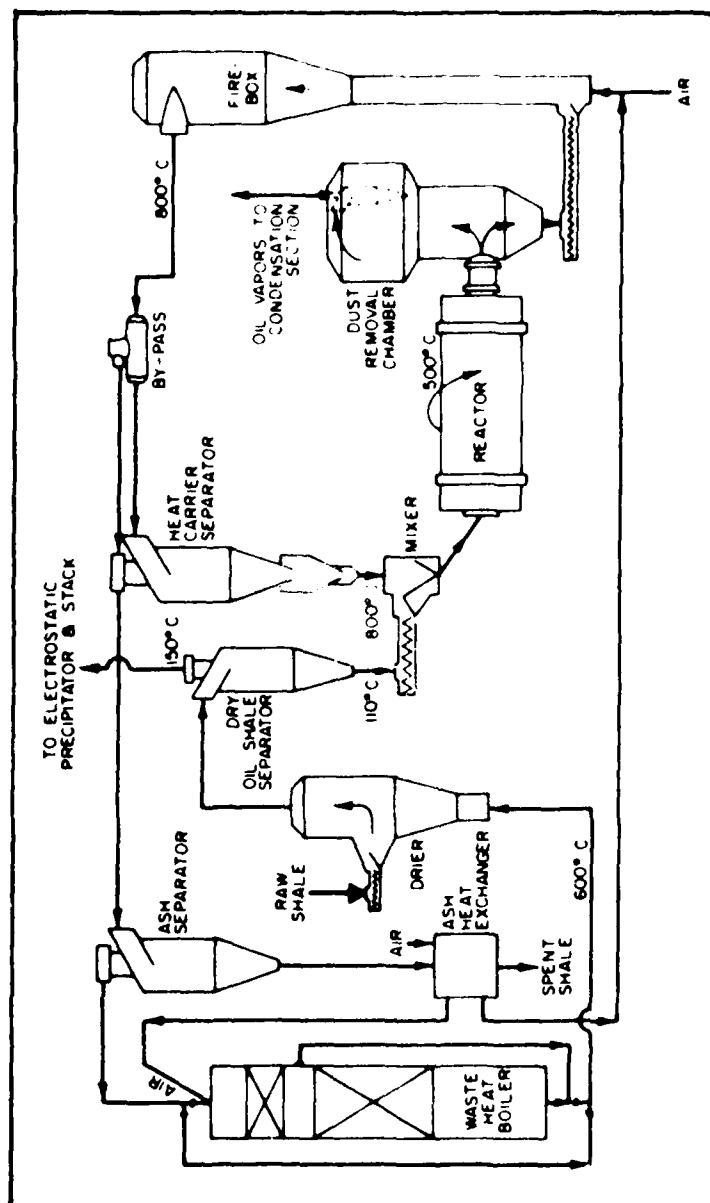
FIGURE 19

Galoter Retorting Process

TABLE 12

Properties of Crude Shale Oil from
Galoter Process
(Baltic Shale Feed)

Density at 68°F, g/cm^3	1.01
Viscosity at 167 ft, Engler	4.5
Pour Point, °F	5
Coking Value, %	8
Phenols, wt %	28
Calorific Value, Gross, Btu/lb	17,010
Distillation, vol %	
Initial B.P., °C	190
200°C	1
250°C	6
300°C	21
360°C	45
Elemental Composition (dry basis):	
Carbon	83.3
Hydrogen	10.0
Sulfur	0.7
Oxygen plus Nitrogen	6.0
	100.0

The Petrosix process was developed by the engineering staff of the Brazilian Petroleum Company (Petrobras) for processing Irati and Paraiba Valley shales. The Petrosix process, shown in Figure 20, is the forerunner of the Paraho indirect heated retort that uses externally heated recycle gas to provide heat for retorting. The processes are very similar, and the description of the Paraho indirect heated retort illustrates the operating details of the Petrosix retort. The oil product from the Petrosix retort exhibits the properties indicated in Table 13.[10] Of particular interest is the higher sulfur content and the significantly lower nitrogen content of the crude oil from the Petrosix retort.

TABLE 13

Properties of Crude Shale Oil from Petrosix Process

Density, °API	19.6
Diolefins, wt %	15.0
Sulfur, wt %	1.06
Nitrogen, wt %	0.85
Paraffin, wt %	0.02
Aniline Point, °F	86
Pour Point, °F	25
Viscosity at 100°F, centistokes	20.76

FIGURE 20

Petrosix Retorting Process

The Geokinetics process, an example of true in situ (TIS) retorting, uses a fracturing technique called surface uplift in which an explosive is injected into several wells and detonated to fracture the shale and to make it permeable to fluid flow.[141] The shale is ignited by injecting air and fuel gas through one well, and the kerogen is pyrolyzed by the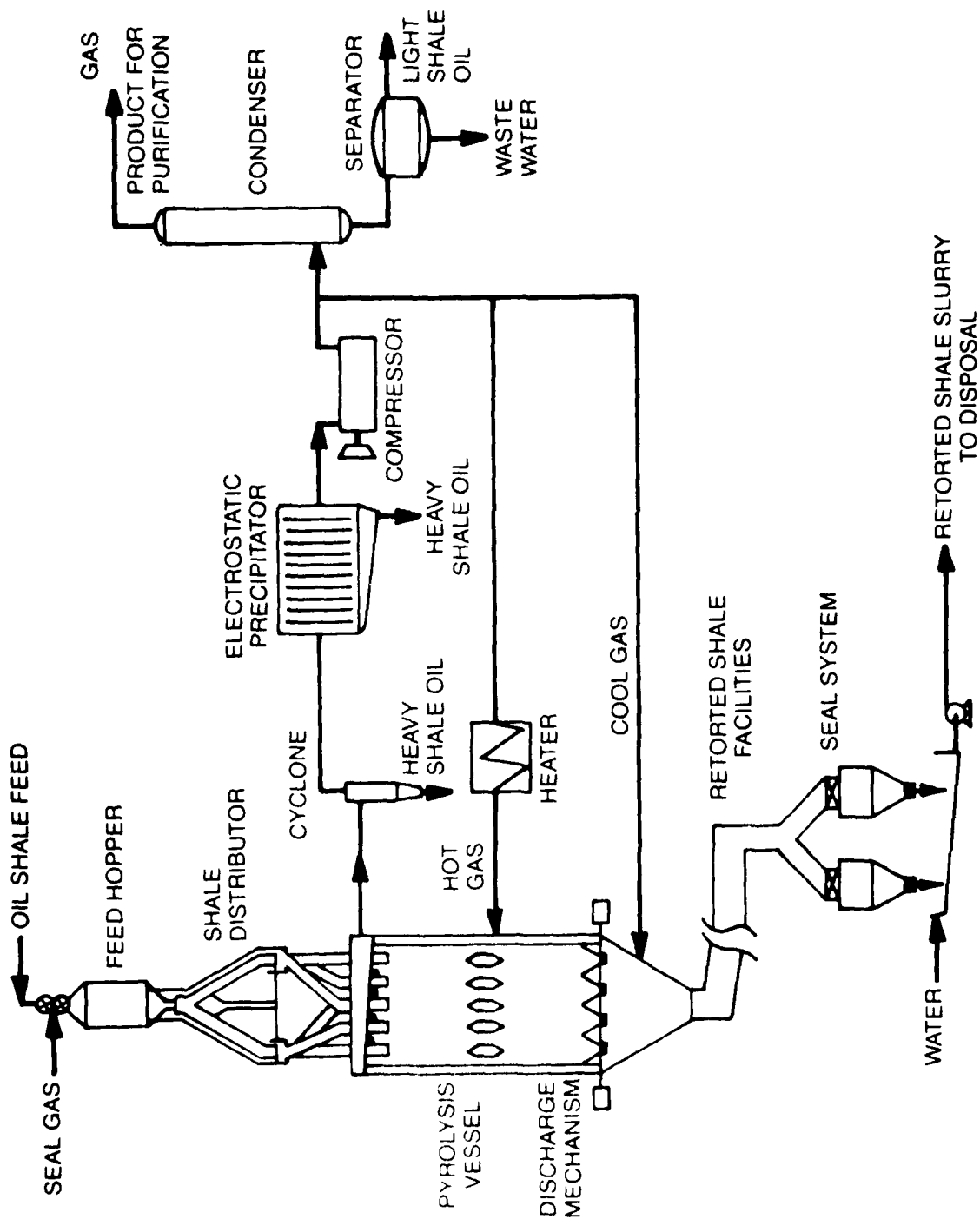 hot gas stream that flows through the shale bed. The primary use for the Geokinetics process lies in the development of the shale deposits that are covered by less than 100 ft of overburden, such as those in the Uinta Basin of eastern Utah.

The sections presented above do not exhaust the supply of retorting techniques that are in various stages of development. However, they do present examples of the basic types of retorting techniques that are either in advanced stages of development or are being considered for use in commercial oil shale development operations.

Effects of Selected Retorting Variables

Each retorting process described in the previous sections produces an oil that is unique to that process. Operating parameters, such as retorting temperature, pressure, shale grade, and shale particle size, combine to make the combination of yield and quality of oil product from each process slightly different from that of every other process. However, just as in other processing systems, there exists a set of retorting parameters that can be used to predict the effect that changes in operating conditions will have on oil yield and quality.

One such operating condition is the temperature at which retorting is conducted. A temperature of 900°F is generally considered to be that at which retorting takes place. However, oil can be obtained from shale at temperatures below 900°F. The penalty for retorting at lower temperatures lies in the quantity of oil that can be derived from a given grade of shale. Table 14[10,63] shows the effect of retorting temperature on oil yield. In general, one can assume

that the lower the temperature at which retorting is conducted, the lower the oil

yield that can be expected for a given grade of shale.

TABLE 14

Effect of Temperature on Oil Yield

Test	Temperature °C	°F	Pressure psig	Duration hr	Oil Yield University of Utah wt %	Fischer Assay wt %	University of Utah % of Fischer Assay
D-4	331	628	0	550	4.0	11.9	33.6
D-5	347	657	0	425	4.8	11.9	40.4
D-19	353	667	0	159	4.3	11.0	39.1
D-7	364	687	0	312	6.0	11.4	52.6
D-22	395	743	0	71	7.6	10.6	71.6
D-16	399	750	0	86.5	8.0	11.0	72.8
D-17	420	788	0	38	8.8	11.0	80.0
D-10	427	801	0	37.5	8.9	11.4	78.1
D-14	427	801	1,000	14.7	8.6	11.8	72.9
D-1	500	932	0	13.5	7.6	8.2	92.6

Retorting temperature also plays a role in determining the quality of the

oil that is obtained from a given shale. Table 15 [10, 63] shows the effect of

retorting temperature on oil gravity and pour point. In general, a lower retort-

ing temperature produces a higher API gravity and lower pour point oil product.

This phenomenon is explained in two parts. First, the collection of oil product

from shale involves the decomposition of the kerogen in the shale to an oil and

gas product. The oil is subsequently vaporized, and the gas and oil vapors are

swept from the retort. A lower retorting temperature will result in only the

light fractions of the oil being vaporized, swept from the retort, and collected

as oil product. This product, as it contains only the light ends, will have a

higher API gravity and lower pour point. As the retorting temperature is

increased, heavier fractions of the oil in the retort will be vaporized and col-

lected. This will result in a product with a lower API gravity and a higher pour

point.

TABLE 15

Effect of Temperature on Oil Quality

Test	Temperature °F	Temperature °C	Specific Gravity gm/cm³	Gravity °API	Pour Point °C	Fischer Assay Specific Gravity gm/cm³
D-4	628	331	0.822	40.7	-40	0.911
D-5	657	347	0.823	40.5	-45	0.911
D-19	667	353	0.828	39.4	-23	0.914
D-7	687	364	0.817	41.6	-18	0.912
D-22	743	395	0.838	37.4	-20	0.910
D-16	750	399	0.828	39.4	-23	0.914
D-17	788	420	0.832	38.6	-20	0.914
D-10	801	427	0.888	27.7	-5	0.912
D-14	800	427	0.814 (1,000 psig)	42.3	-22	0.903
D-1	932	500	0.852	34.6	10	0.907
D-2	968	520	0.859	33.5	0	0.907

The second part of the explanation for higher quality oil at lower temperatures involves the process of thermal cracking. Cracking is a phenomenon by which large oil molecules are thermally decomposed into smaller, lower boiling molecules.[106] At the same time, some of the more reactive molecules combine with one another to yield even larger molecules than those in the original material. A portion of the product from a retort in which cracking is taking place will be a shorter chain, lower boiling product, but as the retorting temperature is increased or the residence time at the elevated temperature is increased, the overall quality of the resulting oil product will be reduced. Table 16 shows this effect as it relates to a gas oil from conventional petroleum.[106] The principle also applies to shale oil.

TABLE 16

Cracking Tests of Emba (Russian) Gas Oil

No. of Operation	Time min at 450°C	Yield, wt % Below 200°C (392°F)	Yield, wt % After 350°C (672°F)	Gravity, °API Cracking Stock and Recycle Oils	Gravity, °API Below 392°F	Gravity, °API Above 672°F	Approximate Characterization Factor Recycle Oils	Approximate Characterization Factor Gasolines
1	42	28.7	10.5	30.8[1]	58.2	10.6	11.4[1]	11.9
2	52	21.3	8.6	28.2	52.5	1.05[2]	11.2	11.6
3	75	16.3	7.9	23.8	46.0	1.116[2]	10.9	11.2
4	101	12.1	10.3	19.2	38.4	1.777[2]	10.5	10.8
5	101	3.9	12.4	15.4	37.1	1.157[2]	10.3	10.6
6	160	8.0	19.0	14.5	30.6	1.243[2]	10.2	10.3

[1] Emba gas oil (uncracked).
[2] Specific gravity.

Cracking can also be a result of the retort configuration and the grade of the shale being retorted. In a typical vertical kiln retort, the products of pyrolysis pass through a cooler zone of raw shale. If these products are very rich in shale oil, some of the oil will tend to condense before leaving the retort. The condensed oil will then flow back down the retort into a zone of much higher temperature in which it will revaporize and thermally crack into shorter chain molecules. The same polymerization process described earlier also occurs, and the overall result is a poorer quality product.

Another parameter that has an effect on oil yield and on quality is the retorting rate, or the rate at which the shale is heated to yield liquid and gaseous products. Tests conducted with shale samples containing 10.1, 25.6, and 49.4 gal of oil per ton of shale showed that increased heating rates result in reduced yields of liquid and gas products and poorer product quality.[6] In these tests, the effect of increasing the heating rate from 4°C/min to 40°C/min was a 23% decrease in the yield of liquid and gas products. In addition, a higher heating rate favored the formation of higher boiling components in the product oil. Other researchers have noted that preheating the shale at a temperature far below that at which retorting occurs causes a significant reduction in oil

yield if the preheating is carried out in air.[25] Five-day tests at 120°C showed a 19% reduction in oil yield compared to a sample that had not been preheated, and 25-day tests at 120°C showed a 34% reduction in oil yield. However, preheating in an inert atmosphere at the same temperature and for the same length of time had no effect on oil yield. The oil product from preheated shale was a heavier product that exhibited significantly higher aromaticity than the unpreheated shale. Table 17 shows a comparison of the composition of preheated and unpreheated shale.

TABLE 17

Analysis of Oil Product

Component vol %	Oil Source	
	Fresh Shale	Preheated Shale (25 days - 120°C)
Saturates	26	22
Olefins	48	46
Aromatics	26	32

The ambient differences between operating conditions of surface and in situ oil shale retorts cause notable differences between the properties of the oil products from these two processes.[49] Crude shale oils produced by in situ combustion retorting of Green River oil shale normally have higher API gravities and lower viscosities and pour points than crude shale oils produced in NTU or gas combustion retorts. In situ crude shale oils also contain a much higher percentage of material boiling below 1,000°F.

The preceding discussion is intended to serve only as a guide in determining the effect that changes in various operating parameters will have on oil yield and quality. Each retorting process being developed for commercialization in the United States combines these parameters in different ways to maximize the total benefit gained for each invested dollar.

This means that operating conditions are adjusted so that concessions are made in one area of production to reap an increased benefit in another. A

sacrifice in oil quality may lead to increased production and an overall increase
in the return on investment. However, a decrease in the quality of the crude
shale oil product does not necessarily imply that a corresponding decrease in the
quality of the final fuel products will result. The following section, which
deals with shale oil upgrading and refining techniques, will show that, given the
proper processing equipment, one can achieve almost any desired level of quality
in the final products derived from a particular feed material.

SHALE OIL UPGRADING AND REFINING

The production of transportation fuels from shale oil has been the subject
of several extensive research projects, and the results have indicated that a wide
range of high-quality fuels can be produced from shale oil using existing tech-
nology. The particular processing scheme used depends largely on the properties
of the feed material, the desired product slate, and the required product qual-
ity. The following sections will discuss shale oil properties, which tend to
dictate the processing scheme to be used, previous research efforts concerning
the refining of shale oil into transportation fuels, and the capabilities of U.S.
refineries to convert shale oil into high-quality transportation fuels.

Shale Oil Properties

Crude shale oil and conventional petroleum are both liquid hydrocarbon mate-
rials, which, with suitable processing, can be transformed into a wide range of
fuels. The particular processing methods depend, in part, upon the properties of
the feed material being processed. The refinery operations that are used to pro-
cess conventional petroleum crudes are well established, state-of-the-art opera-
tions that have been successfully used in the refining industry for many years.
However, they are specifically designed for processing materials with the physi-
cal and chemical properties of conventional petroleum. The properties of shale
oil are, in some cases, significantly different from those of conventional crude
and, as a result, present a unique problem to the refiner. Table 18 presents a

comparison of some conventional crude properties with those of shale oil produced by various retorting methods.[2, 10, 53] As shown in the table, the properties of crude shale oils differ markedly from conventional crude oil in the areas of pour point and nitrogen, arsenic, and iron content.

For conventional petroleum crudes, the pour point, in °F, is considered a rough indicator of the relative paraffinicity and aromaticity of the crude.[54] However, in a more practical sense, the pour point is an indication of the "pipelineability" of the crude oil. For example, conventional petroleum crudes having a pour point of less than 15°F can easily be transported from production areas to refining centers through unheated pipelines. Crude shale oils, on the other hand, have a pour point of 60°F or more and, therefore, are not as amenable to transport through unheated pipelines. If the crude shale oil is to be transported to refining centers via pipeline, the pour point must be reduced to a level such that the shale oil can be more easily, and less expensively, pumped through the pipeline. Solutions to this and other problems are discussed in the following sections.

The nitrogen content of crude shale oil is another property that differs significantly from conventional crude oil. Table 18 shows that the nitrogen content of a typical crude shale oil is an order of magnitude greater than that of conventional petroleum crudes. This high concentration of nitrogen presents a particular problem to refiners in that nitrogen compounds act as poisons to the catalysts used in reforming and cracking operations and result in excessively high rates of catalyst deactivation.[54] Nitrogen compounds present an additional problem in that their presence in finished products contributes to gum formation, an indication that the fuel cannot be stored for very long before being consumed.[166] This is a particular problem in the case of military fuels, which may be stored for 2 or 3 yr before being used.

TABLE 18

Comparison of Selected Properties of
Conventional Crude Oil and Crude Shale Oils

	Conventional Crudes	TOSCO II	Paraho Direct Heated	Union "B"	Oxy (In Situ)
Gravity, °API	15-44	21.2	21.4	22.7	25
Pour Point, °F	<15	80	85	60	70
Nitrogen, wt %	0.01-0.65	1.9	2.15	1.74	1.5
Sulfur, wt %	0.06-4.1	0.9	0.63	0.81	0.71
Oxygen, wt %	N.A.[1]	0.8	1.40	0.90	1.13
Arsenic, ppm	0-0.030	40	19.6	48	N.A.
Nickel, ppm	0.03-45	6	6.1	6	N.A.
Iron, ppm	0.696-68.9	100	71.2	55	N.A.
Vanadium, ppm	0.002-348	3	0.37	1.5	N.A.

[1] Not available.

Arsenic and iron are two more crude shale oil components, which are present in concentrations significantly greater than are observed in conventional crude oil. They also act as reforming and cracking catalyst poisons because of their affinity for the metals (platinum, cobalt, nickel, etc.) that form the active sites of these catalysts. They also have a strong affinity for the metals contained on the catalysts used to remove nitrogen from crude shale oil.[34] Figure 21 illustrates the relationship between the activity of a nickel-molybdenum catalyst used for shale oil denitrogenation and the amount of arsenic-laden shale oil treated in tests performed by the Atlantic Richfield Company.[34] As shown, there was a significant difference between treating raw shale oil and dearsenated shale oil. Figure 22 illustrates the effect that the drop in catalytic activity had on product oil quality for the same series of tests. Clearly, any arsenic present in the crude shale oil that is fed to catalytic upgrading operations will have deleterious effects on the catalyst used in those operations.

Another difference between the properties of crude shale oil and conventional crude oil is the distillation range observed for each of the two oils. Figure 23 illustrates the difference between the distillation range of crude shale oil and of conventional crude oil.[90] The shale oils were produced from Utah shale by the Paraho direct heated and Union "B" retorting processes. This figure shows that, while conventional crude oil contains a greater amount of low-boiling material which can be refined to gasoline, it also contains a greater amount of high-boiling residuum. The distillation range of shale oil is restricted to that of material that is normally refined to distillate fuels such as jet and diesel fuels. Figure 24 shows a similar comparison between conventional crude, shale oil, and other synthetic crude oils.[43]

There are other differences between the physical and chemical properties of crude shale oil and conventional crude oil, but the properties discussed above are generally regarded as those requiring different processing of the two oils.
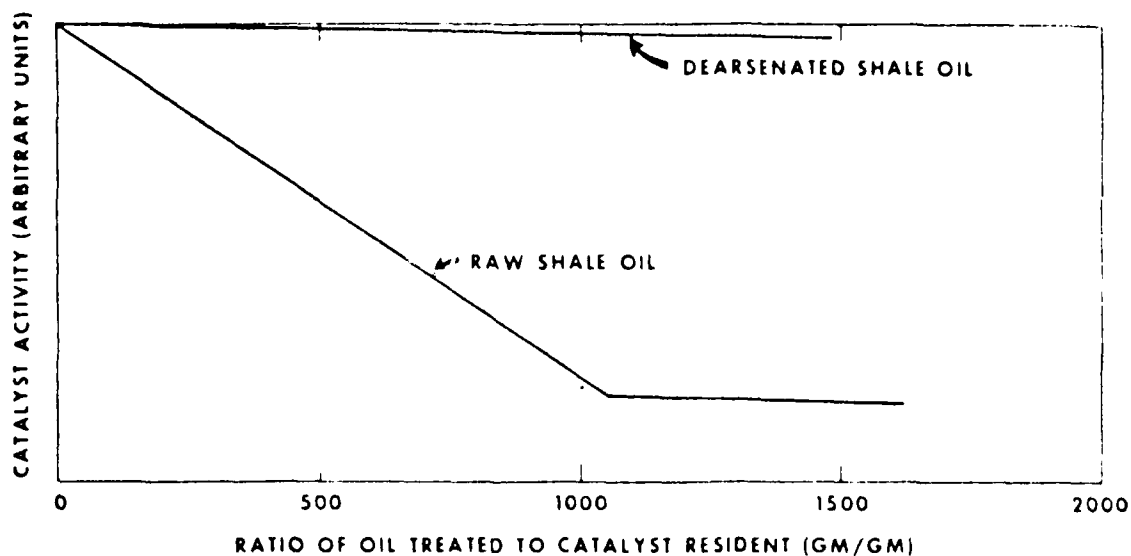
FIGURE 21

Catalyst Activity of a Nickel-Molybdenum Catalyst
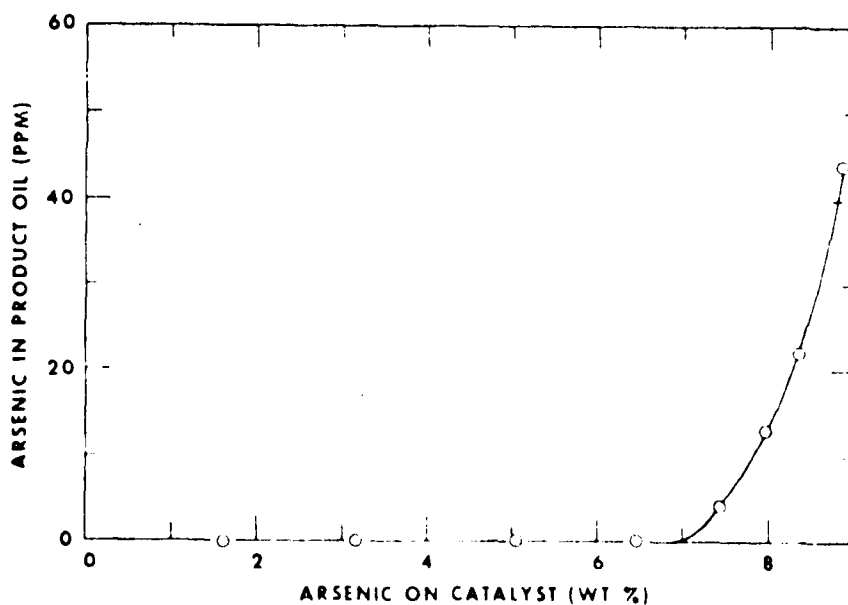Treating Shale Oil

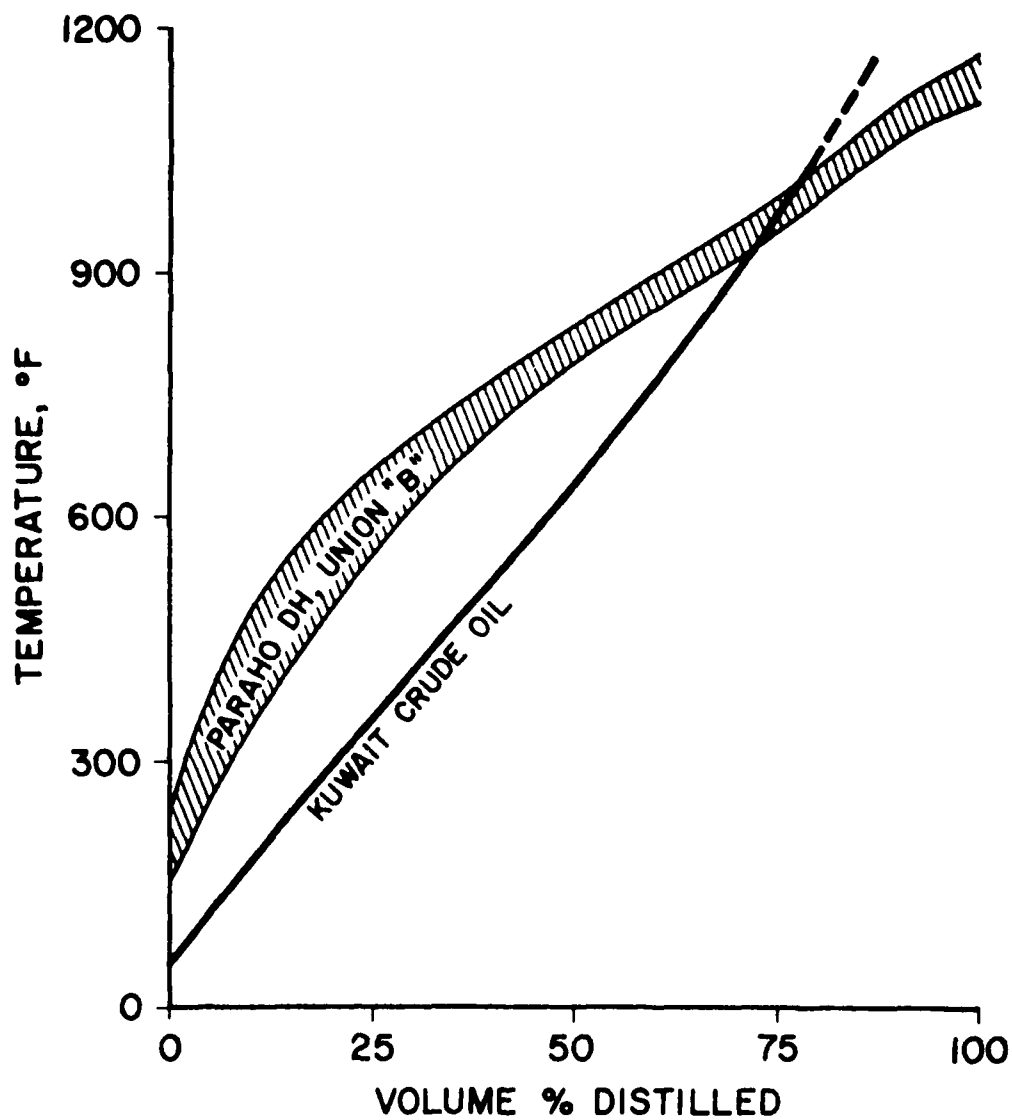FIGURE 22

Arsenic in Hydrotreated Product Oil

FIGURE 23

Comparison of Distillation Ranges of
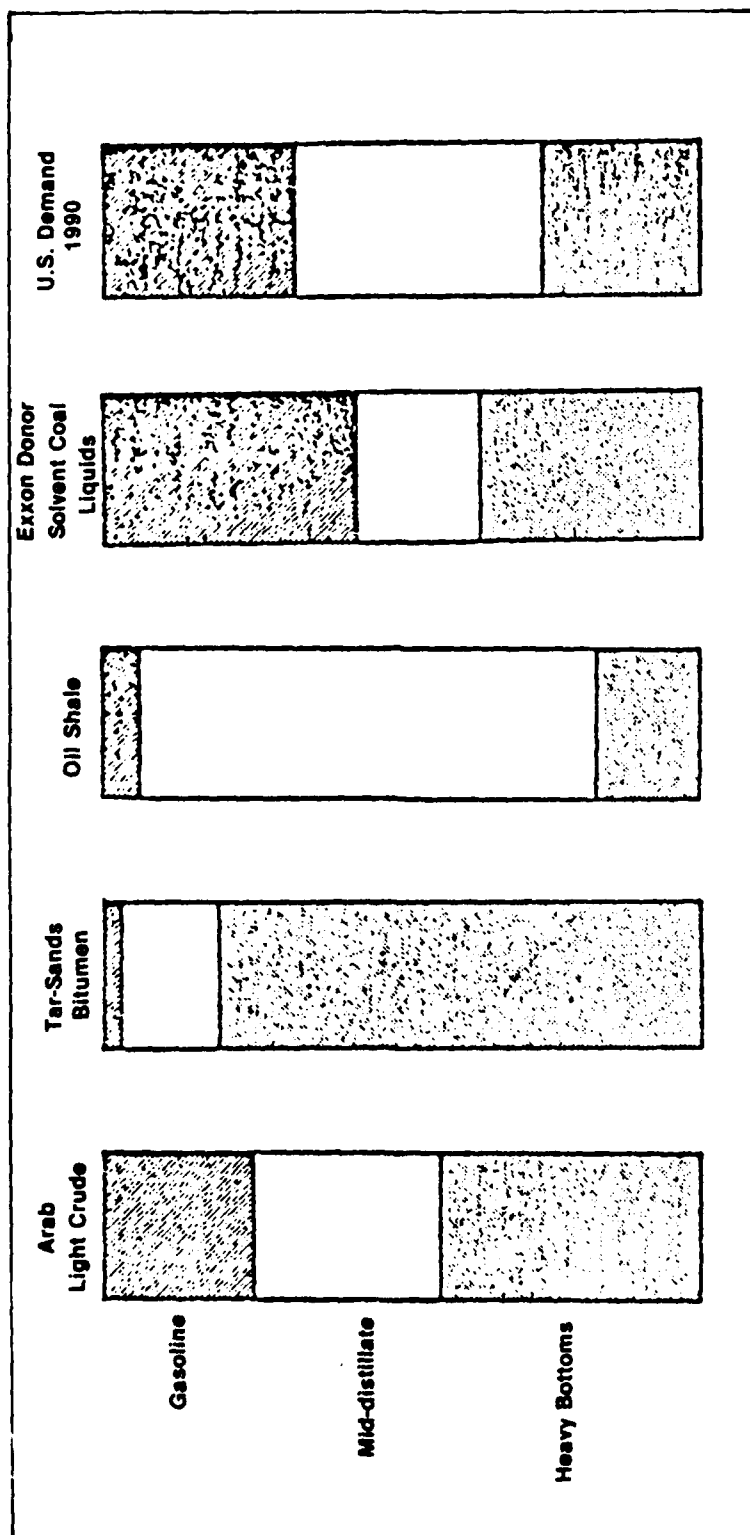
Shale Oil and Conventional Crude Oil

FIGURE 24

Comparative Composition of Various Crude Oils

The next section describes a few of the processing operations that have been used or postulated for use to convert shale oil into transportation fuels.

Decription of Unit Operations

Understanding the processes used to upgrade or refine shale oil and their impact on product quality and yield is important. The following are descriptions of the techniques used either to upgrade the crude shale oil to a high-quality synthetic crude or to refine the crude shale oil to finished fuels.

Additives

The use of pour point depressants to increase the ease of raw shale oil transportation has proven successful in some instances. However, a particular chemical that works well with one type of shale oil may not work at all with oil from another retorting process. Furthermore, the addition of pour point depressants does not improve the chemical characteristics of the oil, and thus the cost of the additive must be recovered solely in the savings in transportation charges.

Another material that may be considered a blending agent is conventional petroleum. Because shale oil from Colorado will be produced in the same geographical location as existing petroleum reserves, the possibility exists that the lighter petroleum crude could be mixed in appropriate proportions with crude shale oil to form a transportable product. The viability of this concept highly depends on the changing economics of the refining industry, as the resulting shale oil/petroleum crude product would perhaps not be as desirable a feedstock as the petroleum crude alone. While the unit value would be less, the increased volume may offset the disadvantage. Only a thorough economic evaluation could determine the economic trade-offs of the concept.

Visbreaking

Visbreaking involves heating the crude shale oil to approximately 900° to 980°F and maintaining this temperature for several seconds to several minutes.

The hot oil product is subsequently cooled, and the gases are separated. During the process, little or no reaction occurs to reduce the content of nitrogen, sulfur, or oxygen in the oil. Therefore, the primary result o. the process is pour point and viscosity reduction. This technique, if applied to crude shale oil with a pour point of 85° to 90°F would probably produce an oil with a pour point of approximately 45° to 50°F.[102]

Coking

Coking involves heating the feed to 900° to 980°F and then charging it to another vessel in which thermal decomposition occurs. If the oil is charged to a coke drum, it is called delayed coking. The coke is allowed to build up to about two thirds of the drum volume, and then the feed is switched to another drum while the coke is cleaned out of the first vessel.

The hot oil can also be charged into a fluidized bed of coke particles. In this "fluid coking" process, the coke particles become coated with oil, which then decomposes to yield gases and another layer of coke. The gaseous products are recovered from the vessel, and the coke particles can be withdrawn at a rate sufficient to maintain bed inventory.

A process known as flexicoking, developed by Exxon, involves conventional fluid coking followed by gasification of the product coke. This would represent a valuable use of the coke product, but tests would have to be conducted to determine if the coking characteristics of crude shale oil would be appropriate for the use of this technique.

Catalytic Treating (Hydrogenation)

Catalytic hydrogenation processes yield the highest quality products but also are very expensive. During this process, the sulfur is converted to hydrogen sulfide, the nitrogen to ammonia, the oxygen compounds to water, the unsaturated hydrocarbon chains to paraffin homologues, and the long-chain molecules to shorter chain molecules.

The hydrogenation reactions can take place in a fixed bed reactor through which a mixture of partially or totally vaporized oil and hydrogen is passed. The reactions may also occur in a fluidized bed reactor or an "ebullated" bed. The latter technique has been proposed by Hydrocarbon Research, Inc. (HRI) in their H-Oil process, which has been successfully used on heavy petroleum feedstocks and residuum fractions. In this process, a liquid-gas mixture is injected into the bottom of the reactor at a sufficient velocity to cause catalytic motion, or a "boiling" of a bed. This movement of the bed minimizes the potential of bed plugging due to formation of tars and coke. It also allows spent catalyst and coke to be removed and fresh catalyst to be added to maintain active bed inventory.

The operating limitations of the hydrogenation reactor will dictate the allowable composition of the feedstock. Fixed-bed reactors would most likely be used to hydrotreat streams from an initial shale oil fractionator, whereas the fluid or ebullated bed processes could operate either on fractionator product streams or on whole shale oil.

Distillation

Distillation is a process by which the feed shale oil, either crude or partially upgraded, is separated into fractions according to boiling point so that subsequent processing units will have feedstocks that meet their particular requirements. The higher boiling fractions such as gas oils (650°F+) are removed from the lower portion of the distillation column, while progressively lower boiling fractions such as middle distillates (350° to 650°F), heavy naphthas (90° to 180°F), and uncondensed gases (90°F-) are removed from progressively higher locations in the column. Each stream is then sent to a processing unit designed to handle feedstocks of that boiling range to produce fuels with the desired characteristics. If changing the boiling range of the material being fed to a unit is necessary, the operating conditions of the distillation column

can possibly be changed such that the boiling range of any given stream is broadened, narrowed, increased, or decreased. In general, the flexibility of the distillation column makes it one of the first processing units used to refine the crude oil into finished products.

Catalytic Cracking

Catalytic cracking is the most important and widely used refinery process for converting heavy oils into lighter products.[54] The catalytic cracking processes in use today can all be classified as either moving-bed or fluidized-bed units. The moving-bed units, of which the Thermofor process is an example, use catalyst beads or cylinders approximately 1/8 to 1/4 in. in diameter while the fluidized-bed units use catalysts with an average particle size of about 50μ.

In either unit, coke is produced in addition to the gasoline and other light liquid products. The coke remains on the catalyst particle and rapidly reduces its activity. To maintain catalytic activity, burning the carbon off the catalyst particles and recycling the regenerated catalyst back into the cracking reactor is necessary. Figure 25 shows three possible configurations for the cracking reactor and catalyst regenerator.[54] In general, catalytic crackers, either moving bed or fluid bed, are used to increase the yield of gasoline from a given feedstock.

Hydrocracking

Catalytic hydrocracking supplements the catalytic cracking process previously described in that the catalytic hydrocracker is capable of processing heavier feedstocks. The high temperature and pressure hydrogen atmosphere present in the hydrocracking reactor make it possible to saturate the unsaturated hydrocarbons which are formed by the cracking reaction. The product from a catalytic hydrocracker is, then, a material boiling in the gasoline range which is very low in unsaturates and is, therefore, a premium quality fuel.
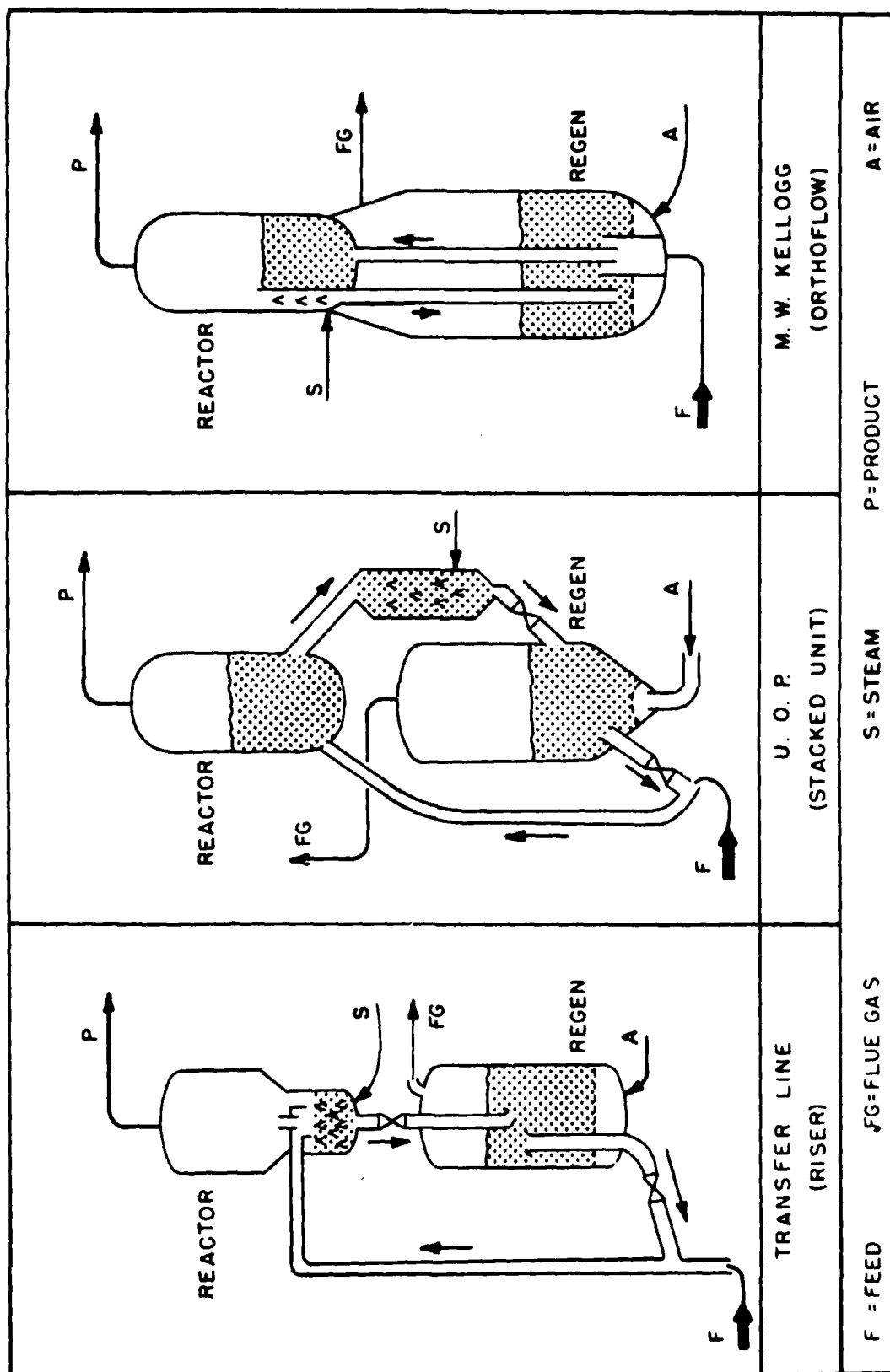
FIGURE 25

Fluid Catalytic Cracking (FCC) Unit Configurations

The primary difference between catalytic hydrocracking and the catalytic hydrogenation process described earlier lies in the ability of the hydrocracking catalyst to promote the formation of small, low-boiling molecules while the hydrogenation catalyst facilitates the removal of nitrogen, sulfur, and oxygen, which act as poisons to catalytic cracking and catalytic hydrocracking catalysts. Both will promote the saturation of unsaturated compounds, but the hydrocracking catalyst more readily promotes the cracking of high-boiling material to lower boiling, more valuable products.

Catalytic Reforming

Catalytic reforming is a process by which the structure of the feed material, usually heavy naphtha with a boiling range from 180° to 375°F, is rearranged to form higher octane aromatic molecules. Table 19 presents typical analyses of catalytic reformer feed and product streams.[54]

TABLE 19

Typical Analyses of Catalytic Reformer
Feed and Product Streams

Component	Volume, %	
	Feed	Product
Paraffins	45-55	30-50
Olefins	0-2	0
Naphthenes	30-40	5-10
Aromatics	5-10	45-60

Light naphtha streams are generally not fed to catalytic reformers since they tend to crack to butane and lighter fractions, thus reducing the yield of gasoline. Similarly, middle distillate streams are not fed to catalytic reformers, because they are easily hydrocracked and cause excessive carbon laydown on the catalyst, thereby reducing its useful life.[54]

Catalytic reformer catalysts are very susceptible to deactivation by certain metals, hydrogen sulfide, ammonia, and organic nitrogen and sulfur compounds. As a result, reformer feed streams are typically subjected to a

catalytic hydrogenation pretreatment step to remove these materials. This pre-treatment is not severe enough to remove the amounts of these materials present in shale oil naphthas that had not previously undergone a severe hydrotreating step. For this reason, the hydrogenation step used to pretreat catalytic reformer feedstocks cannot be considered as a replacement for the severe hydro-treating of either the whole crude shale oil or the heavy naphtha stream.

Given the proper combination of the above refinery operations, conversion of any crude shale oil into acceptable quality fuel is possible.

Previous Refining Studies

With the growing interest in synthetic fuels as a possible solution to an increasing reliance on foreign crude oil supplies, considerable work has been conducted in recent years on the subject of shale oil upgrading and refining. A review of the available literature related to the refining of crude shale oil indicates that the three primary factors involved in the design of the refining scheme are:

1. Characteristics of the crude shale oil.

2. Desired product slate.

3. Equipment and operating constraints of the proposed facility.

The first of the above factors probably has the least effect on the refining scheme selected, as the characteristics of crude shale oil, as a general rule, do not vary widely relative to conventional petroleum crudes. The impact of the second factor, product slate, may be noted in the literature by the changes in proposed configurations as the emphasis on gasoline production has diminished from the early 1950's to today. That is, early research by the U.S. Bureau of Mines proposed the extensive use of middle distillate cracking and reforming to produce gasoline/distillate ratios of nearly 3.0,[86] whereas most configurations proposed in recent studies emphasize diesel fraction production with gasoline/distillate ratios of 0.25 or less.[157]

The third factor, equipment and operating constraints, has become increasingly important in recent years. The deliberate, "modular" approach to developing an oil shale industry implies that in the near- to mid-term, the quantity of shale oil produced will not be sufficient to warrant a new dedicated refinery. Thus, more recent refinery research has been aimed at processing shale oil either in existing refineries modified for the purpose, or at least through the use of readily available equipment commonly used in existing facilities.

Generalizing the various proposed refining schemes into only a few "typical" schemes is difficult, as there are any number of possible configurations into which the basic refining processes can be arranged. The fundamental operations involved were described in the preceding section. Depending on the product slate desired and the operating conditions employed in the processes, a large number of configurations can be developed using these processes, which will achieve the desired results. The configuration selected will be dependent on equipment availability and individual refinery economics as much as any other technical factor.

One fundamental difference among the various configurations is the sequence of distillation and thermal or catalytic treatment. In general, the proposed configurations can be divided into those processes that distill the crude shale oil into various component fractions prior to subsequent thermal or catalytic treatment, and those processes that initially upgrade the crude shale oil by thermal or catalytic means prior to distillation and further treatment.

One of the cited advantages of the second approach is that the severity of downstream treatment processes does not need to be as great as it does with configurations of the first type. On the other hand, configurations involving initial distillation of the crude shale oil usually provide better control over the specification of the individual fractions.

Research to date has concentrated primarily on processing configurations that involve thermal or catalytic treatment of the shale oil prior to distillation into its various component fractions. Figures 26 through 28 are simplified schematics of three such processes. Figure 26 illustrates the refining scheme used in the late 1940's by the Bureau of Mines at Anvil Points,[83] which produced a gasoline/distillate ratio of about 3.0. Figure 27 illustrates a configuration investigated by Chevron U.S.A. during pilot-plant runs on Paraho shale oil.[157] This technique yielded a gasoline/distillate ratio of about 0.25. Both of these processes employ coking as the means to initially upgrade the shale oil feedstock and to produce a product stream that can more easily be further refined into liquid fuel products. One of the shortcomings to incorporating a coker into the refining process is that some amount of coke will be produced, and this commodity may not have a readily available market.

Figure 28 is a generalized schematic of another refining scheme investigated by Chevron U.S.A. in pilot-plant runs with Paraho shale oil.[157] In this process, a fixed-bed hydrotreater using conventional catalyst was used to upgrade the shale oil prior to distillation. By this technique, no coke is produced, as most of the heavy ends of the crude shale oil are upgraded by the hydrogenation process into more valuable liquid fuels. Because this route is more costly than the coking approach, only detailed economic evaluations will determine which configuration will ultimately be the most economic. During its investigations, Chevron also studied the possibility of substituting a fluidized catalytic cracker for the hydrocracker in Figure 28. A similar processing scheme was also employed by The Standard Oil Company (Ohio) when the company refined 100,000 bbl of Paraho shale oil at the Toledo refinery.[124] The primary difference between the Toledo run and Figure 28 was that acid/clay treatment was used to upgrade the distillate cuts from the distillation column into JP-5 and diesel fuel marine for military
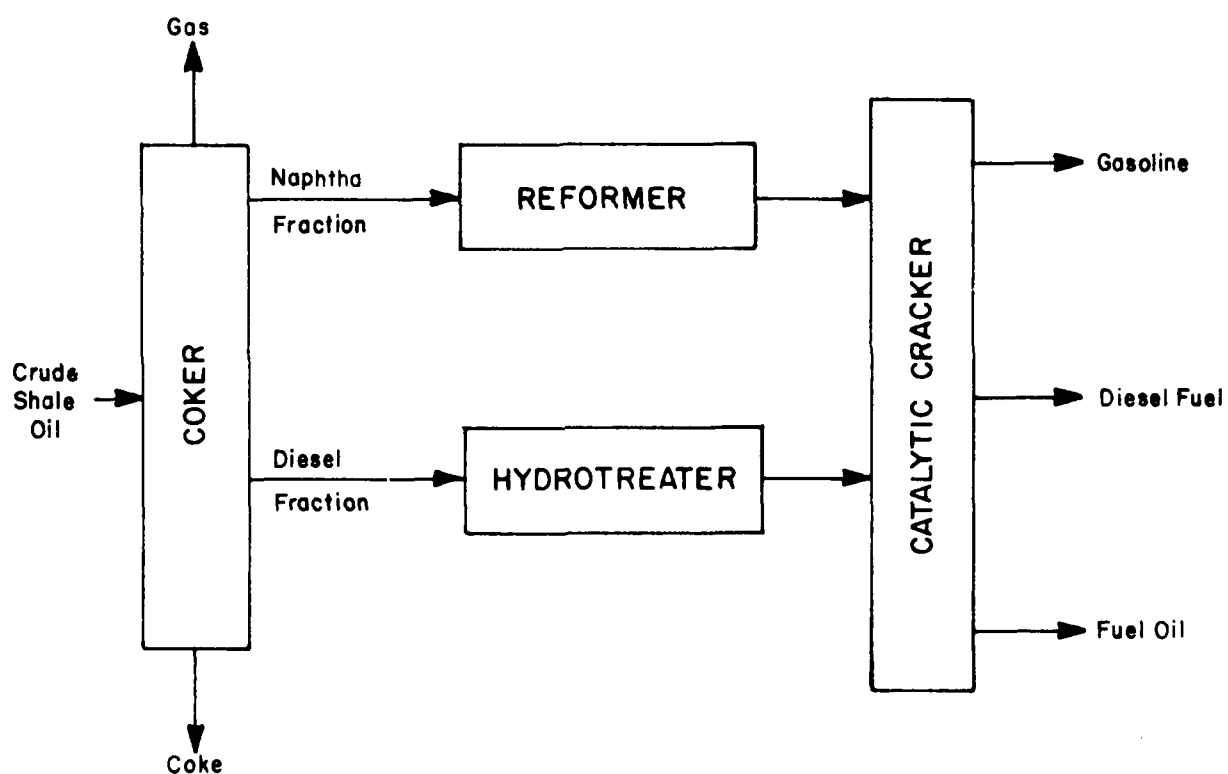
FIGURE 26

U.S. Bureau of Mines Refining Scheme Emphasizing Gasoline Production
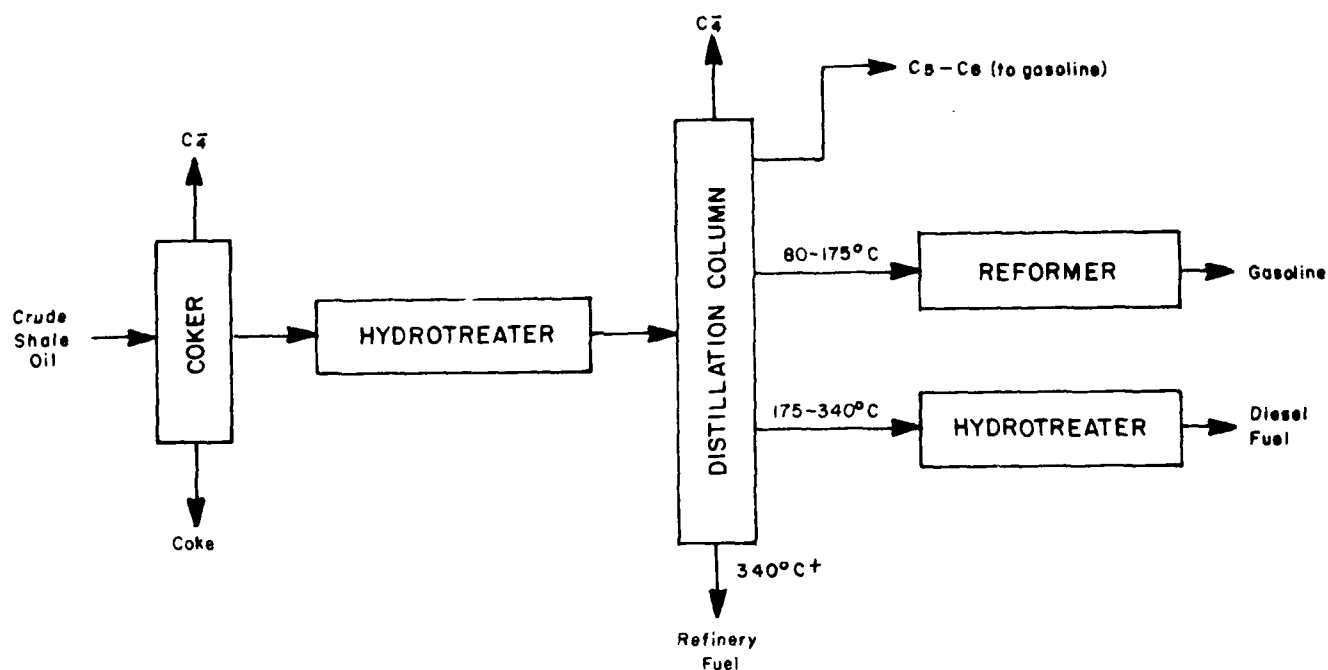
FIGURE 27

Chevron U.S.A. Refining Scheme
Emphasizing Distillate Fuels Production
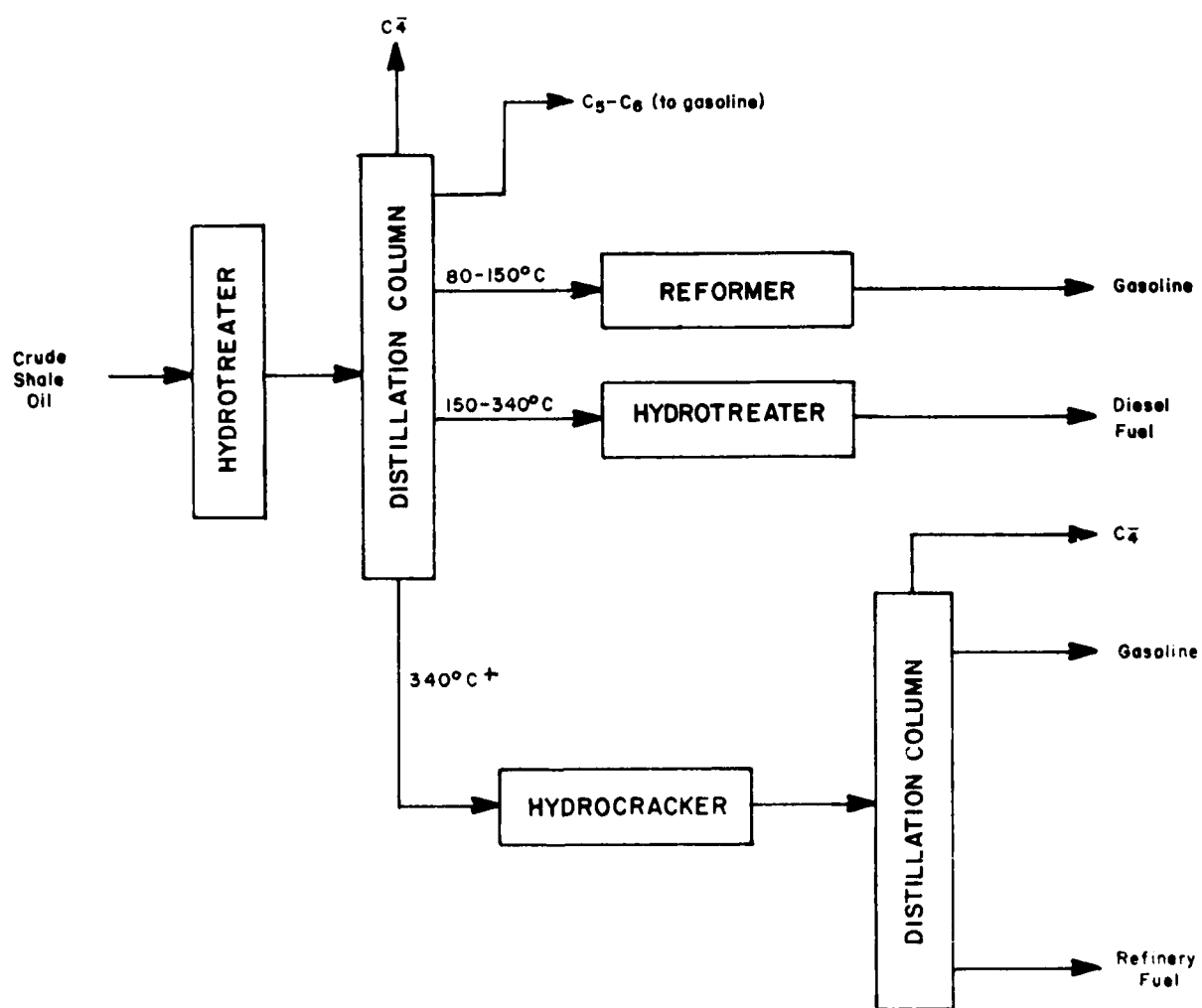
FIGURE 28

Chevron U.S.A. Refining Scheme
Emphasizing Raw Shale Oil Hydrotreating

purposes and the bottoms from the distillation unit were merely used for refinery fuel.

An example of a configuration in which the crude shale oil is fractionated prior to treatment is shown in Figure 29. This is a simplified flow diagram of the process used during the prerefining studies performed by the Standard Oil Company (Ohio) in preparation for the 10,000-bbl refining run of Paraho shale oil at the Gary Western Refinery near Fruita, Colorado.[9] During the actual refinery run, a coker/fractionator unit was used rather than the totally separate units as shown in the figure.

Another very important processing step that must also be addressed is shale oil pretreatment. One of the primary functions of this step is to remove from the shale oil excess amounts of water which may cause cavitation problems in pumps and steam explosions in downstream processing. Another is the removal of ash or particulate matter from the oil to prevent deposition in pipes, heat exchangers, and catalyst beds. Recent studies have shown that by heat treating at 75°C and by allowing the oil to stand for approximately 6 hr, the oil/water emulsion can be broken, and the water and solids can be settled out.[157]

Because arsenic acts as a catalyst poison to most conventional hydrotreating catalysts, crude shale oil containing this trace element must be pretreated to remove the arsenic. A variety of processes have been developed for the removal of arsenic, and, therefore, the presence of the material is no longer viewed as a serious problem as long as the economics can justify the expense of pretreatment. ARCO has developed several patented techniques employing heat treatment in the presence of hydrogen as well as several catalytic techniques (Atlantic Richfield Co.). Recent studies by Chevron U.S.A. have shown that a guard bed containing alumina with a moderate surface area effectively removed both arsenic and iron contaminants.[157]
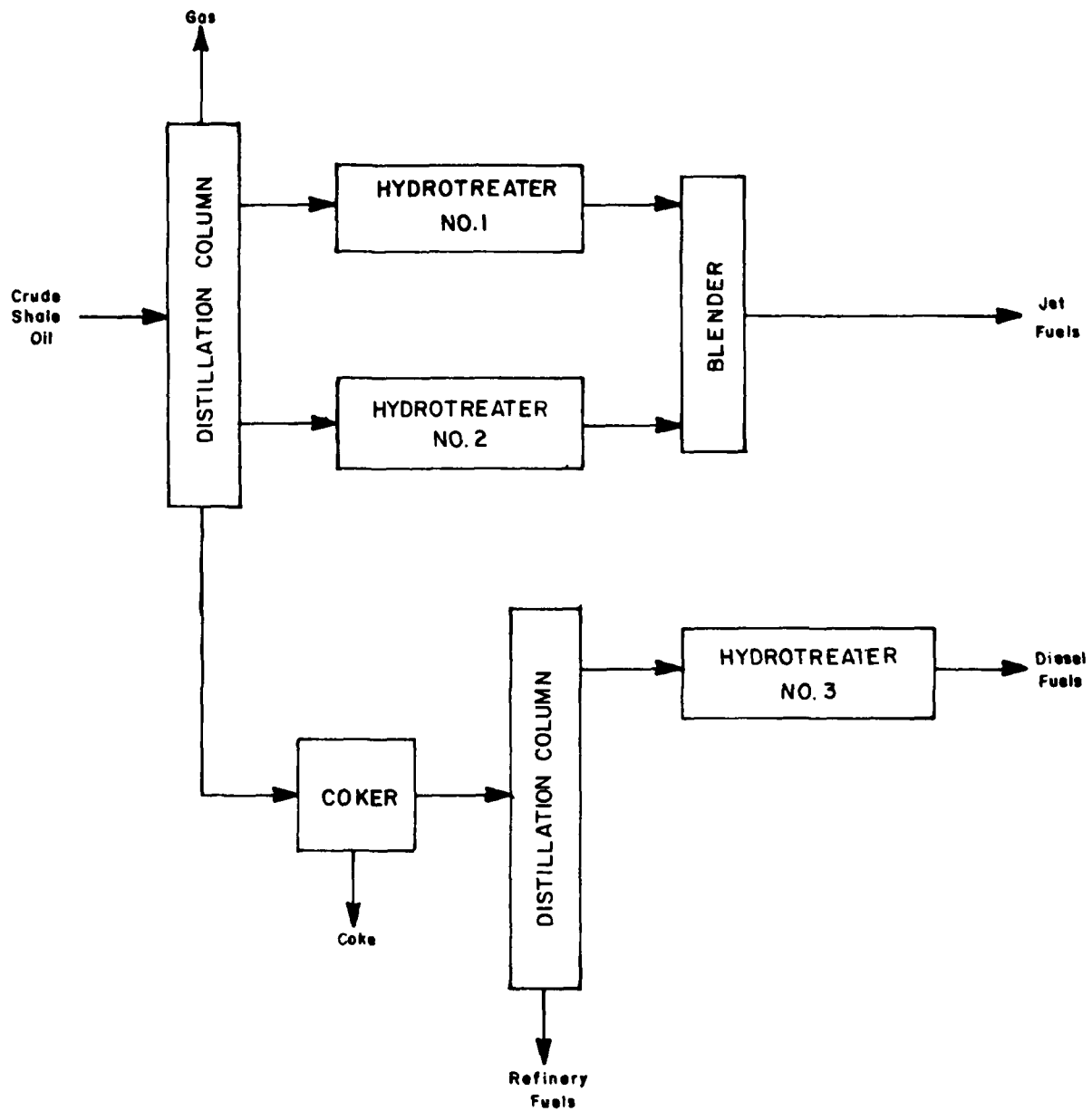
FIGURE 29
Standard Oil Company (Ohio) Refining Scheme
Employing Initial Shale Oil Fractionation

The particular refining equipment configuration and operating conditions employed will dictate not only the quantity of fuel products produced but also their quality. Fuel products produced by the Bureau of Mines refinery at Anvil Points, Colorado, performed quite satisfactorily in tests. However, several fuels produced from Paraho shale oil in the Gary Western refinery during 1975 failed to meet all the desired military specifications, principally those related to fuel stability.[5] It is now generally accepted that these difficulties may be attributed to the use of inadequate hydrotreating facilities and to product contamination. Subsequent refining tests performed by the Standard Oil Company (Ohio) at its Toledo refinery[165] show that with the use of appropriate refining techniques, fuels of superior quality meeting all specifications can be produced from shale oil.

Many factors must be considered when evaluating the costs of producing fuel products from shale oil feedstock. These include market availability and stability, ease of product distribution, availability of equipment or refining sites, but a generalized cost study is sometimes helpful. Some of the most recent research in the area of shale oil refining costs has been conducted by Chevron U.S.A.[50] During the study, Chevron evaluated the costs of three different processing schemes: a combination of hydrotreating and hydrocracking (see Figure 28), hydrotreating followed by fluid catalytic cracking, and delayed coking followed by hydrotreating (see Figure 27). The results of the study showed that for a production rate of 100,000 bpcd of light products from a grass-roots refinery in an urban Rocky Mountain region, the refining cost would be approximately $8 to $10/bbl. For a production rate of 50,000 bpcd of light products from a refinery in a remote Rocky Mountain region, the cost would be approximately $10 to $12/bbl.

A research program is also being conducted by the Air Force Aero Propulsion Laboratory at Wright Patterson AFB to investigate jet fuel qualities, costs, and processes for producing high yields of aviation turbine fuel from crude shale oil. Three companies (Ashland Research and Development, Suntech Inc., and UOP Process Division) are under contract to the Air Force to develop a processing scheme for converting crude shale oil into jet fuel, to evaluate the economics of this processing scheme, and to provide approximately 1,000 gal of shale-derived jet fuel samples for testing and evaluation. The processing schemes used must meet the following goals:

- Be novel, yet show demonstrated potential for scale-up.
- Maximize the yield of jet fuel while limiting the yield of residual fuel to no more than 10% of the products.
- Have an overall thermal efficiency of at least 70%.
- Have potentially lower costs for converting whole crude shale oil into a slate of military specification products than "state-of-the-art" processing as exemplified by the Chevron Research Company work.

All three companies have presented encouraging results based on their individual processes. Product quality specifications were met in all cases and preliminary economic analyses showed that JP-4 and JP-8 can be produced at costs from $25.15/bbl (reported by Ashland) to $42 to $46/bbl (reported by UOP and Suntec).[14]

Shale Oil Markets

Crude shale oil has essentially three potential end uses: boiler fuel, refinery feedstock, and chemical feedstock. That shale oil will find applicability in only one of these markets is unlikely; rather, the ultimate market will be composed of a mix of these uses. Furthermore, this market mix will change with time. In the early to mid-1980's, when the first significant quantities of shale oil will likely become available, the probable market will be in boiler fuel applications, with a small quantity going to local refineries capable of

processing the shale oil without extensive modifications and captital expendi-
tures. As more shale oil becomes available, its value as a refinery feedstock
will be enhanced due to the decreasing availability of conventional petroleum.
Later still, the boiler fuel market will probably decline, and shale oil will
begin to find applicability as a petrochemical feedstock. Figure 30 is a graphi-
cal representation of the anticipated distribution of shale oil to each of these
markets.[108]

Primarily due to government regulation, the current trend of the utility
industry is to replace natural gas-fired boilers with coal-fired units. For eco-
nomic reasons and due to the nonavailability of coal in certain regions, many
utilities must replace their gas-fired facilities with oil-fired units prior to
making the ultimate switch to coal. In addition, some oil-fired plants cannot
be converted to coal firing and will have to be maintained until they are
replaced by new facilities. During this gas-to-coal transitional period, a mar-
ket for perhaps 50,000 to 80,000 bpd of crude shale oil may exist.

Beyond the utility market, a small demand by the refining industry exists.
Refineries are also changing their boiler fuel requirements from natural gas to
oil, and a localized market for shale oil in these facilities may exist.

Regardless of the application, shale oil will likely find its first use as
a boiler fuel, because there will be relatively little capital investment
required, and only a short lead time is necessary for its utilization in this
market.

The similarities between crude shale oil and conventional petroleum allow
for the refining of shale oil by techniques already well known in the industry.
The differences between the two feedstocks, however, necessitate the expenditure
of considerable capital to modify or to convert existing refineries or to con-
struct new facilities to refine shale oil. This capital expenditure, along with
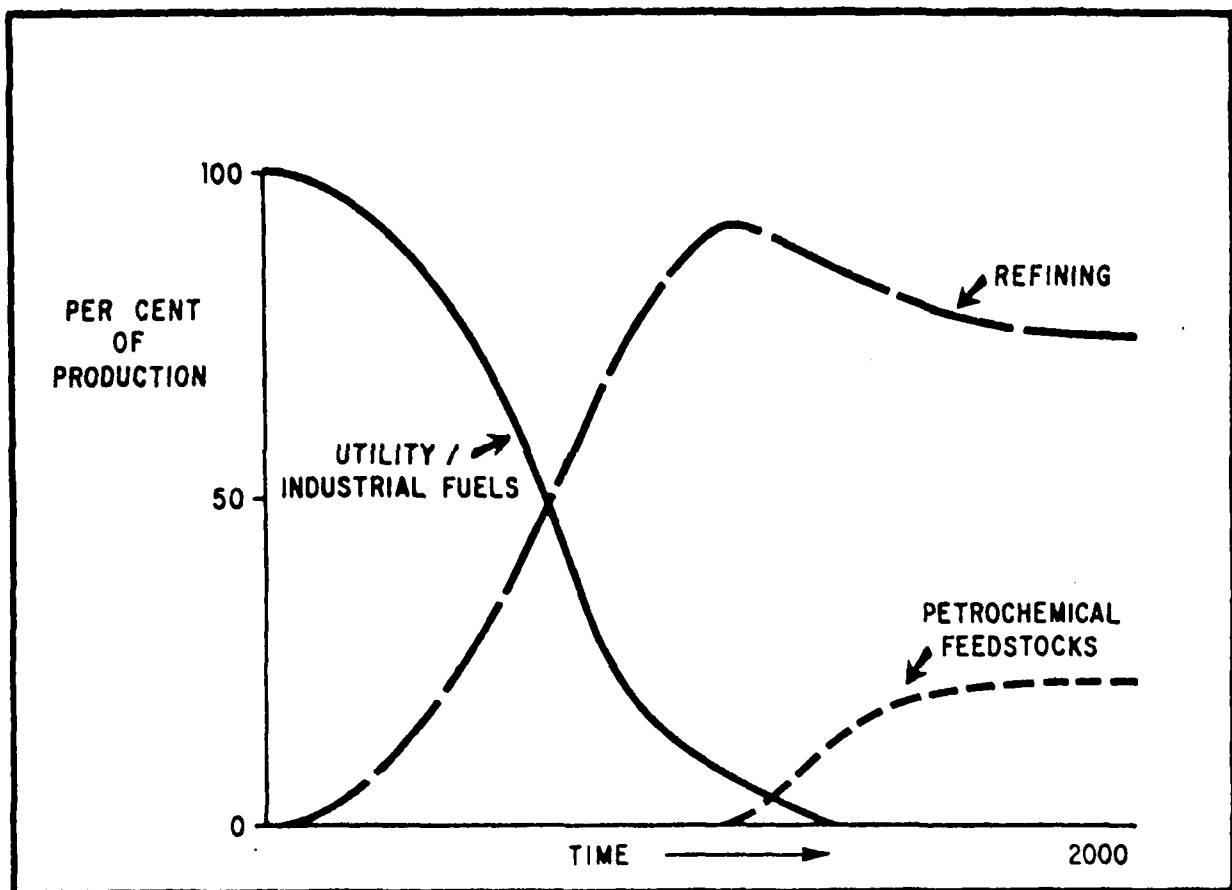
FIGURE 30

Projected Shale Oil Allocation

the risk inherent in the pioneer oil shale industry, represents a barrier that must be overcome before shale oil is accepted as a viable alternative feedstock.

Oil shale developers recognize that a market must exist for their oil if they are to make any money by producing it. Likewise, most refiners realize that shale oil may be available one day and may serve as an alternate feedstock at their facilities. In spite of this, there has been relatively little research conducted to date on shale oil refining. An analysis of the oil shale and refining industries reveals several possible reasons why this situation exists. First of all, the relative time frames used by the industries are significantly different. Once a commitment is made by an oil shale developer to construct a commercial facility, significant quantities of product will not be produced for 5 to 7 yr. On the other hand, a refiner can run a preliminary evaluation on a new crude in days, develop a viable processing scheme in weeks, conduct the necessary prerefining studies in months, and modify his facility to accommodate the new feedstock in less than 3 yr. Knowing that the technology currently exists to handle crude shale oil, neither the oil shale developer nor the refiner has great incentive to exhaustively study shale oil refining until he is assured that the shale oil will be produced. A second possible reason is the emphasis of refining industry on present and near-term production, with a somewhat lower priority given to more long-term prospects.

Another factor that causes most industry observers to minimize the need for exhaustive refining studies at the present time is this country's continuing critical shortage of liquid fuels. As this shortage continues or grows, the desirability of shale oil, our most available resource for liquid fuels, will gain importance. Furthermore, the desirability of shale oil is increasing as market conditions change. Since the 1950's, gasoline demand has continued to grow, and the refining industry has developed sophisticated techniques for

maximizing gasoline yields at the expense of the heavier distillate fractions. Because shale oil produces primarily middle and heavy distillates, with very little gasoline-fraction yield, it was considered a less desirable feedstock. Using available crudes with high gasoline yields was considered more cost effective than converting a greater proportion of the distillate to gasoline in shale oil. However, most major forecasters project gasoline demand to peak in the early 1980's and to decline slightly thereafter.[99, 121] This is primarily the result of automobile efficiencies increasing faster than the growth of vehicle miles driven and of a penetration of diesel engines into the automobile and truck markets. In addition, available crude supplies are, as a rule, getting heavier, and the refining industry is adjusting to this change by installing the appropriate equipment. Compared with the alternatives, shale oil is becoming a more premium feedstock.

There are four basic facilities that could realistically refine crude shale oil:

1. A new "shale oil only" refinery.

2. A new refinery designed to handle a petroleum/shale oil feedstock mix.

.3. An existing refinery modified for and dedicated to shale oil refining.

4. An existing refinery handling a petroleum/shale oil feedstock mix.

For now, the overcapacity of the U.S. refining industry would negate consideration of a new refinery running a petroleum/shale oil blend, and most recent shale oil marketing studies also rule out a dedicated grassroots refinery in the foreseeable future. Shale oil produced at least through the 1980's will likely be refined in existing refineries, either as the sole feedstock or in a blend with conventional petroleum.

The relatively small quantities of shale oil produced by demonstration operations will likely be processed either by local refiners (e.g., Gary Western in Fruita, Colorado; Little America in Rawlins, Wyoming; Chevron in Salt Lake City, Utah; etc.) or in captive refineries operated by the oil shale developers or principals themselves. The larger quantities produced by a mature industry will have to compete with other feedstocks on a larger scale. Most recent market studies have determined that the most reasonable market area for crude shale oil is the Midwest, including the states in Petroleum Administration for Defense District (PADD) II. (See Figure 31). This, of course, is not to say that the other geographic areas of the country will not be affected by this shale oil marketing, as the crude petroleum, which the shale displaces in PADD II, will then be available elsewhere or will not have to be imported at all, if it was originally from a foreign source.

Within the PADD II and PADD IV areas, most refiners are interested in the prospect of shale oil availability. However, the capabilities of the various refineries dictate the suitability of a shale oil feedstock, and, therefore, the level of interest on part of the refiner. In addition, the long-range availability of petroleum crude also determines a particular refiner's level of interest in shale oil. The section of the country within the described geographical area having the most uncertain supply of petroleum crude for future processing requirements is the northern tier of states including Montana, North and South Dakota, Minnesota, and Wisconsin. These states have historically been very dependent on imported Canadian petroleum. A significant reduction in the supply of Canadian crude in recent years has led the refiners in this area to look elsewhere for feedstocks. Current plans call for pipeline construction to allow for transport of Alaskan and imported crude to the area. If a pipeline route to the area from the shale oil production sites could be devised, this area could represent a substantial shale oil market.
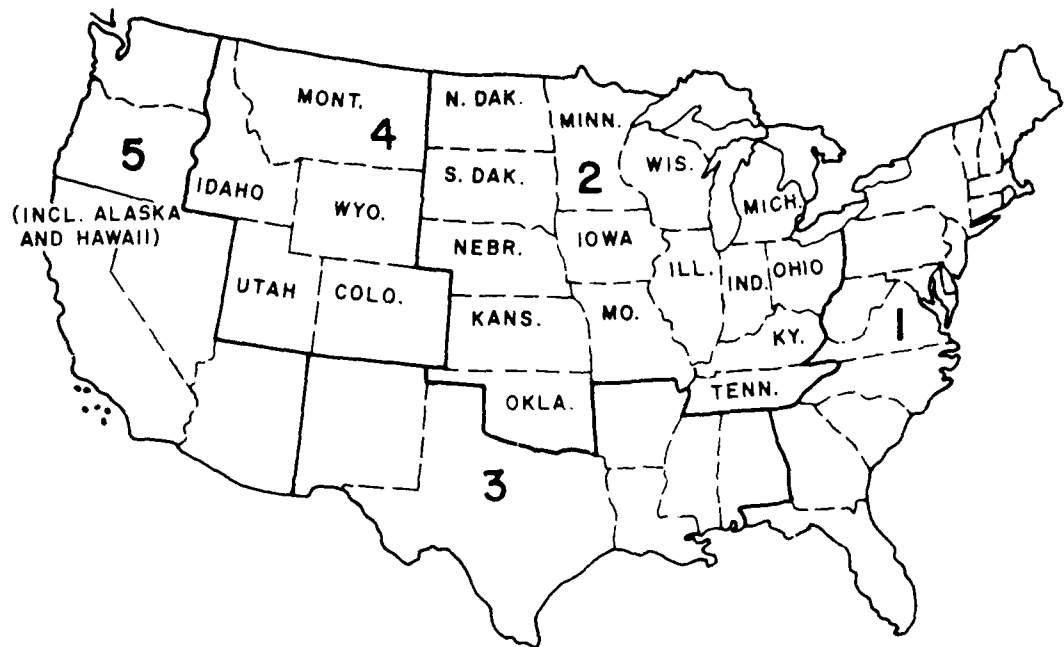
FIGURE 31

Petroleum Administration for Defense (PAD) Districts
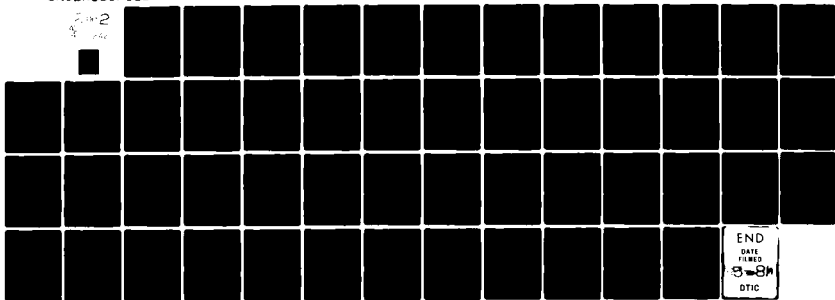
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The area including Iowa, Missouri, Illinois, Indiana, Michigan, and Ohio does not have adequate indigenous supplies of petroleum to meet the market demands, but unlike the northern tier states, this area has a good pipeline supply system providing access to both foreign and domestic supplies. The shale oil market in this area will largely be controlled by the economic trade-offs between the shale oil and foreign petroleum, and this will be controlled to some extent by governmental regulation. Recent marketing studies[116] have identified in this geographical area several large refineries that have the capability to handle crude shale oil with only limited modifications. Furthermore, some of the area refineries beginning to process heavier crudes are being limited in their capacity by the ability to process bottoms.[116] Shale oil, with a relatively small bottoms fraction, may help alleviate this difficulty.

Three primary factors must be considered when evaluating the applicability of shale oil as a petrochemical feedstock:

1. Petrochemical yields obtainable from shale oil.

2. The ability of existing and future petrochemical plants to process shale oil.

3. The logistics involved in getting the shale oil to the petrochemical plant.

Crude shale oil usually has a high olefin content due to the pyrolytic processing involved in its production, and it has a respectable hydrogen content, relative to many conventional petroleum crudes, of approximately 12%. Both crude shale oil and the hydrogenated products derived from it have been demonstrated in several recent investigations to be appropriate feedstocks for petrochemical production.[57] Using steam pyrolytic techniques, crude shale oil can yield quantities of total olefins comparable to those obtainable from many conventional petroleum feedstocks. Even greater yields are obtainable from hydrogenated shale oils, thus making them premium grade petrochemical feedstocks.

The studies that led to the above conclusions were conducted on bench-scale equipment under carefully controlled conditions. If present or future petrochemical plants do not have the capability to operate under these conditions, there of course will be no market for the shale oil as a feedstock. Historically, the primary feedstock for petrochemical plants has been natural gas liquids from the Gulf Coast. As the domestic production of natural gas declines, resulting in a decreased supply of natural gas liquids, the petrochemical industry is shifting to heavier feedstocks such as naphtha and gas oil. The supplies of both of these feedstocks are dependent upon government regulation (e.g., additional naphtha demand due to stricter TEL restrictions) and seasonal demand (e.g., winter demand for gas oils as heating fuels). Because of this, most new ethylene facilities are being designed and constructed with considerable feedstock flexibility. It would be reasonable to expect that as heavier feedstocks, such as gas oils, become more predominant in the industry, shale oil will be viewed with more favor than at the present time.

One often-cited disadvantage of shale oil as a petrochemical feedstock is the distance between the source and the market. While the refining industry is fairly well distributed throughout the country, as are oil-fired boilers, the petrochemical industry is located almost exclusively on the Gulf Coast. For a variety of reasons, including continued feedstock availability, proximity to by-product and derivative markets, storage facilities, and others, the regional concentration is likely to continue for the foreseeable future. As this impacts shale oil utilization, either the shale oil must be transported to the Gulf Coast, or a new petrochemical plant must be built in the Rocky Mountain region, and the various products then must be transported to the Gulf Coast for further processing. Of the two options, the former is the most likely, at least in the near future. As the petrochemical industry moves to heavier feedstocks and the availability of foreign crude is decreased, the current lack of a pipeline

system and the high cost of alternative transportation methods are problems that may be rectified.

In summary, neither crude shale oil nor hydrogenated products can be considered viable petrochemical feedstocks in the near future, primarily due to the inability of the existing industry to process the materials and to the transportation constraints in getting the shale oil feedstock to the market. Tests have shown, however, that given the proper operating conditions, shale oil can be a valuable feedstock, and the future petrochemical industry will likely be able to capitalize on this value.

Shale Oil Transportation

Assuming that markets for shale oil will exist in several geographical locations and allowing for the fact that economics will ultimately determine how the markets are prioritized, an examination of the economics of transporting shale oil from the area in which it is produced to the area in which it will be marketed is necessary. Table 20 presents comparative transportation costs for shale oil and foreign crude oil to several potential market areas.[108] The figures assume pipeline transportation to a typical destination within the area. Where existing pipelines are in place, actual tariffs are used. Tariffs are approximated for new pipelines using $.20/bbl per 100 mi for 200 mbpd, and $.10/bbl per 100 mi for 1,000 mbpd.

TABLE 20

Relative Transportation Economics
Shale Oil Versus Foreign Crude Oil, $/bbl (1977)

| | Shale Oil | | | (Penalty)/Premium | |
	200 mbpd	1,000 mbpd	Crude Oil	200 mbpd	1,000 mbpd
Los Angeles	1.80	0.90	0	(1.80)	(0.90)
Rocky Mtn.	0.60	0.30	0.80	0.20	0.50
Chicago	1.20	1.20	1.20	0	0
U.S.Gulf	2.40	1.20	0	(2.40)	(1.20)

The obvious conclusion from these figures is that there is a significant transportation advantage to marketing shale oil in the Rocky Mountain/Great Lakes area rather than a coastal location. These results were used to determine which refiners would be contacted in the refinery survey, the results of which are discussed in the following section.

Refinery Survey

Refineries that were contacted during the course of this survey were selected on the basis of their proximity to areas in which shale oil would possibly be marketed and on the likelihood that the refinery could process crude shale oil with existing facilities.[110] Eighteen representatives of refining companies were contacted to obtain site-specific information concerning the ability of the refineries to accept crude shale oil as a feedstock.

Of the fifteen refineries contacted, only three presently have the facilities necessary to accept crude shale oil as a feedstock. Table 21 presents some of the results from the questions that were asked of each refiner. The first item, hydrotreating capabilities, is the most critical of the three. As was discussed in previous sections, hydrotreating is an essential step in producing high-quality transportation fuels from shale oil. Research has shown that in order to remove the nitrogen contained in shale oil, hydrotreaters must operate at pressures of 1,500 to 2,200 psig.[157] Of the fifteen refineries that were contacted, only one, the Marathon Oil Co. refinery in Robinson, Illinois, claimed to have a hydrotreater capable of operating at such high pressures.[12] The Chevron refinery located in Salt Lake City, Utah, has a hydrotreater capable of operating at a pressure of 1,100 psig. Although this pressure is somewhat lower than that stated earlier as necessary to sufficiently hydrotreat raw shale oil, the Chevron refinery has conducted a successful refinery run with a 5 vol % blend of raw shale oil and residual oil coker feed.[17] Other refineries that were contacted had hydrotreaters capable of operating pressures of only 400 to 600 psig. These

TABLE 21

Refinery Survey Results

	Refinery/Location	Hydrotreating Capabilities	Experience With Shale Oil	Anticipated Equipment Modifications	Possible Shale Oil Refinery?
1.	Conoco Commerce City, Colorado	Insufficient Pressure and H_2 Production	None	None	No
2.	Gary Western Company Fruita, Colorado	Insufficient Pressure	Production Run in 1975 of Paraho Shale Oil	Feasibility Study for 10 mbpd Shale Oil Refinery	No
3.	Asamera Oil Company Commerce City, Colorado	Insufficient Pressure and H_2 Production	None	None	No
4.	Conoco Billings, Montana	Insufficient Pressure and H_2 Production	None	Increase Heavy Ends Capability	No
5.	Little America Refining Co. Casper, Wyoming	Insufficient Pressure and H_2 Production	None	None	No
6.	Sinclair Oil Company Sinclair, Wyoming	Insufficient Pressure and H_2 Production	Small Unsuccessful Test Run	None	No
7.	Chevron USA, Inc. Salt Lake City, Utah	1,100 psi Hydrotreater Maybe H_2 Deficient	Test Run w/Oxy Shale Oil	None	Yes
8.	Husky Oil Company Cheyenne, Wyoming	Insufficient Pressure and H_2 Production	None	Just Added Delayed Coker	No
9.	Amoco Oil Company Casper, Wyoming	Insufficient Pressure and H_2 Production	None	None	No
10.	Phillips Petroleum Company Woods Cross, Utah	Insufficient Pressure and H_2 Production	Some Work With Geo-kinetics Oil. Products Were Unstable	None	No
11.	Texaco, Inc. Casper, Wyoming	N/A[1]	None	None	No
12.	Union Oil Co. of California Lemont, Illinois	N/A	None	None	No
13.	Marathon Oil Company Robinson, Illinois	2,000 psi Hydrocracker and H_2 Plant	Only Preliminary Lab Work	None	Yes
14.	Shell Oil Company Wood River, Illinois	Hydrocracker and Idle H_2 Plant	Previous Work Resulting from C-b Activity	None	Yes
15.	Energy Cooperative, Inc. East Chicago, Indiana	Insufficient Pressure and H_2 Production	None	Add HDS Unit, ~1,000 psi	No

[1] N/A = not available.

units are used primarily to pretreat the catalytic reformer feed stream and, in general, have neither the pressure rating nor the throughput capacity to be used as shale oil hydrotreaters.

A major part of a refinery's ability to hydrotreat shale oil depends on whether or not that refinery has a sufficient hydrogen production capacity to provide feed to the hydrotreater. The amount of hydrogen required for processing shale oil depends on the composition of the shale oil (nitrogen, sulfur, oxygen, unsaturates, etc.) and also on the desired composition of the product stream. Obviously, a more severe hydrotreating step will require more hydrogen than a step that only partially hydrotreats the shale oil. For example, the refining run conducted by Standard Oil Company (Ohio) at its Toledo, Ohio, refinery reduced the nitrogen level from 2.02 wt % in the raw shale oil feed to the hydrotreater to approximately 0.35 wt % in the hydrotreater product.[165] Hydrogen consumption during this run was approximately 1,050 scf/bbl of feed. By comparison, tests by the Chevron Research Company showed that reducing nitrogen from 2.18 wt % in the feed to approximately 125 ppm in the product resulted in hydrogen consumption of 2,175 scf/bbl of feed. As this illustrates, a substantial amount of hydrogen is necessary to effectively hydrotreat shale oil.

The Marathon Oil Company refinery at Robinson, Illinois, has a sufficient hydrogen production capacity to facilitate the hydrotreating of raw shale oil, as does the Chevron refinery at Salt Lake City. In addition, the Shell Oil Company refinery at Woods Cross, Illinois, has a large hydrogen production facility that was idle at the time of this survey.[167] The Shell representative who responded to the survey indicated that this refinery also had hydrocracking capabilities. Although the representative would not reveal the operating pressure for the hydrocracking operation, the presence of the hydrogen plant makes it logical to assume that the pressure is sufficient to accept shale oil as a

feedstock. This makes the Shell refinery the third refinery that could probably process shale oil with existing facilities.

Refineries that did not have sufficient hydrogen to process shale oil cited the catalytic reformer as their only source of hydrogen. In the reformer, the conversion of paraffins and naphthenes to higher octane aromatics results in the release of a limited amount of hydrogen. However, this hydrogen is used in the reformer pretreating step that removes potential catalyst poisons from the reformer feed stream. There is no excess hydrogen that can be used in a high pressure hydrotreater. The overall refining capabilities of the three refineries previously identified as possible shale oil refineries are shown in Table 22.[110]

Although these refineries probably have the pieces of equipment necessary to refine some quantity of raw shale oil, an interest in obtaining shale oil to be processed in their refineries is not necessarily indicated. The representatives of all 15 refineries, as well as the three representatives of refining companies, were quick to point out that only a complete analysis of a shale oil sample would determine whether or not their refineries would be appropriate for the refining of a particular oil into a given product slate. In addition to the question of whether or not suitable hydrotreating facilities are available, items such as the capacity of other processing units must be addressed. For example, as was shown earlier, shale oil contains greater percentage of material boiling in the middle distillate range than does conventional crude oil. If a portion of the crude oil fed to a given refinery was replaced with a like amount of shale oil, the pro-cessing units that normally handle middle distillate material would tend to be overloaded, while those processing units that normally handle the lighter naphtha and heavier gas oil fractions would be operating below capacity. Naturally, there is a certain amount of flexibility built into any refinery, but at some point, it becomes uneconomical for the refiner to process any more shale oil or other feedstock than that for which the refinery was designed. Only an analysis

TABLE 22

Refining Capabilities of Three Possible Shale Oil Refineries

Company	Chevron, U.S.A.	Marathon Oil Co.	Shell Oil Co.
Location	Salt Lake City, Utah	Robinson, Illinois	Wood River, Illinois
Crude Capacity,[1] bpcd	45,000	195,000	283,000
bpsd	N.A.	205,000	295,000
Vacuum Distillation[1]	35,500	62,000	95,500
Thermal Operations[1]	8,500	21,800	--
Catalytic Cracking,[1] Fresh Feed	18,000	36,500	94,000
Recycle	1,000	8,000	N.A.
Catalytic Reforming[1]	5,500	47,400	88,500
Catalytic Hydrocracking[1]	--	22,000	33,500
Catalytic Hydrorefining[1]	5,500	6,000	27,000
Catalytic Hydrotreating[1]	5,500	22,000	156,000
Alkylation[2]	4,300	7,600	22,000
Isomerization[2]	750	--	2,900
Lubes[2]	--	--	5,600
Asphalt[2]	--	--	31,000
Hydrogen, MMcfd	--	38.5	57.0
Coke, tpd	350	1,200	--

[1] Charge capacity, bpsd.

[2] Production capacity, bpsd.

Note: N.A. -- not available.

of each potential feedstock can provide an answer to the question of how much, if any, shale oil can be processed in a given refinery.

All of the refinery representatives who were contacted felt that an upgraded syncrude consisting of shale oil that had been severely hydrotreated to remove the nitrogen, sulfur, oxygen, and arsenic could be refined to transportation fuels in any refinery. The removal of these materials would eliminate the major concerns that have been expressed by the refining industry on the subject of shale oil refining. Because nitrogen is the most difficult of the undesirable components to remove from shale oil, it is used as a "yardstick" by the refining industry to determine whether a given shale oil feed is acceptable for a given refinery. Limits that were expressed on the amount of nitrogen that could be present in an upgraded syncrude ranged from nil[17] to approximately 20 ppm.[32] Using these figures as guidelines, an upgraded syncrude from shale oil would be a premium feedstock that could be processed by any existing refinery.

A common point made by all refining industry representatives contacted is that the most important factor to be considered when discussing the feasibility of producing transportation fuels from shale oil is economics. When asked to speculate on the relative costs of refining conventional crude oil and shale oil, one refiner estimated that shale oil processing costs would be $3.50-$4/bbl greater, on an amortized cost basis, than conventional crude oil processing costs due to the hydrotreating requirements associated with shale oil.[17] These additional costs will have to be offset by cost decreases in other areas if transportation fuels from shale oil are to find a place in the market.

POTENTIAL FOR GRASS-ROOTS REFINERY

The refining industry is currently operating at about 70% capacity.[94] The refineries located in the Rocky Mountain and Great Lakes areas generally reflect this industry average. In the Rocky Mountain region alone, there has been estimated to be enough refinery capacity to absorb up to 200,000 bbl of shale oil per

day.[43] This available capacity is more than sufficient to handle the level of shale oil production estimated for the near term and makes it unlikely that a grass-roots refinery will be built to process shale oil. In addition, it is extremely difficult, both economically and environmentally, to site a new grass-roots refinery in the United States.[109] The numerous attempts in recent years have met with only limited success. This is not to say that long-term conditions may not change with the growth of the oil shale industry and result in a climate more receptive to the concept of a grass-roots shale oil refining complex, but in the near term, economic and environmental restrictions create a strong incentive to modify existing refineries.

FUTURE RESEARCH EFFORTS

Because this study is very general and is intended only to provide background on shale oil refining and other parameters affecting the characteristics of transportation fuels derived from shale oil, the Army will probably want to conduct more specific work to acquire additional detailed information. The purpose of this section is to outline several possible areas in which to pursue such follow-on work.

Computer Simulations

One possible approach would be to contract with an appropriate engineering or process development firm to run a refining model. Several companies that have refining models capable of providing valuable information are:

- The Pace Company Consultants and Engineers
- Bonner and Moore Associates, Inc.
- Purvin and Gertz, Inc.
- UOP Process Division

UOP Process Division would be interested in performing a computer simulation as a prelude to performing pilot-plant refining runs.

The Pace Company model is capable of providing information on two bases.[11] First, if the crude feedstock properties, product slate, and product properties are specified, the model provides information on the investment required to construct and operate a refinery that will perform the necessary refining steps. Second, if the crude feedstock properties and the refining capabilities of an existing facility are specified, the model provides information on the products that could be produced from the feedstock as well as the difference between the cost of refining the specified crude and a reference crude.

A project in which two or three cases are examined and the results of the computer simulation are examined by qualified engineers could probably be performed for less than $50,000. An example of a study such as this is the one done by Pace for Occidental Oil Shale, Inc.[99]

Pilot-Plant Tests

In addition to conducting computer runs that would simulate refinery operations, the Army may wish to contract with appropriate companies to produce and to refine a small amount of shale oil to transportation fuels.

Tosco Corporation and The Superior Oil Company, Oil Shale Division, were contacted to determine what the cost would be to produce approximately 100 bbl of shale oil under contract to the Army.[97, 168] The Superior Oil representative indicated that Superior would not be interested in making a production run in the near future. The Tosco representative indicated that a detailed written request would be required before a cost estimate to perform a production run could be provided.

Although a specific estimate of the cost to produce shale oil could not be obtained from oil shale developers, an in-house estimate by CSMRI personnel is that such a project could probably be performed at a cost of $100,000 to $150,000.

The UOP Process Division was contacted to obtain a cost estimate to refine 100 bbl of shale oil into a product slate of 75% diesel fuel and 25% gasoline meeting military fuel specifications.[137] The program outlined by UOP was divided into two phases. The first phase would be a paper study and computer simulation to define the flow sheet and the performance of each unit in the flow scheme. A cost estimate to construct and operate a shale oil refinery based on the previously defined flow sheet would be provided as part of the first phase. The second phase would consist of pilot-plant runs to confirm the estimate of Phase I The estimated cost of Phase I is $50,000 to $100,000, and the estimated cost of Phase II is $200,000 to $300,000.

Other Approaches

Another area that the Army may wish to pursue is to work closely with the companies that are developing the oil shale resource in the United States to obtain accurate, up-to-date information on particular shale oil recovery operations. For example, Union Oil Company and the Colony Development Operation both plan to upgrade the shale oil that they produce and possibly refine it into finished fuels at the retorting site.[158] Therefore, they are in the best position to know what the characteristics of their products will be. The Army would benefit greatly by keeping in close contact with these and other oil shale developers as the industry matures.

Summary

The estimated cost to proceed with a comprehensive prog, that would range from computer simulations of shale oil refining to pilot-plant runs $350,000 to $550,000. This dollar figure must be kept in the proper frame of reference. The estimates were made on the basis of the best information that CSMRI could provide to the individuals making the estimates. This information was very general and often incomplete, and the estimates should be used cautiously. If the Army should decide to continue with this line of research, a more accurate estimate

could be obtained by providing the appropriate companies with detailed information on the nature and scope of the program and on the results that are to be obtained. The companies can then assemble more detailed cost data and form a more accurate estimate of the cost of the program.

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      fis, Colorado School of Mines Research Institute, January 8, 1981.

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      Griffis, Colorado School of Mines Research Institute, January 12, 1981.

APPENDIX

RECORD OF COMMUNICATION

Individual Contacted____Mr. Pat Bell_____Date January 20, 1981_____

Company____Pace Company Consultants and Engineers____
            P. O. Box 53473_____
            Houston, Texas   77052_____

Telephone___(713) 965-0311_____

Mr. Bell was contacted to determine the cost of using Pace's
Refining/Petrochemical Linear Programming Model. Following are
the salient points of that conversation.

- The model can be run in either of two modes. For the
  first mode, the crude oil and product slate are specified
  and the model determines the investment required to con-
  struct a refinery to produce the desired products. For
  the second model, the crude oil and the processing capabil-
  ities of an existing refinery are specified and the model
  determines the difference between revenues from products
  of the specified crude oil and those of a reference crude
  oil.

- The cost of a study similar to the one done by Pace for
  Occidental Oil Shale would be $30,000 to $40,000.

- When crude shale oil is blended with the conventional
  crude oil feed to a refinery in concentrations up to 5 per-
  cent, the additional processing cost is $_ to $3/bbl.
  For blends greater than 5%, the additional processing
  cost is $6 to $9/bbl.

- The model is always available to be run.

- For additional information, contact Mr. Jim Yaccinno,
  (713) 965-0311.

RECORD OF COMMUNICATION

Individual Contacted____Dr. Al Benham_____Date__January 8, 1981____

Company____Marathon Oil Company_____
_____539 South Main Street_____
_____Findlay, Ohio 45840_____

Telephone__(419) 422-2121 ext. 2970_____

Dr. Benham was contacted to determine Marathon's ability to refine shale oil into transportation fuels at any of its refineries in the United States. Following are the salient points of that conversation.

- Of Marathon's four refineries located in the United States, only the refinery at Robinson, Illinois currently has the facilities necessary to refine raw shale oil to transportation fuels. The capacity of this refinery is 195,000 BPD. Dr. Benham did not comment on the availability of any excess capacity.

- Marathon has no need to examine shale oil as a refinery feedstock. However, upon the request of Defense Fuels Supply, they examined a sample of Oxy shale oil and concluded that they could process a certain amount of it, but only with some difficulty. Based on the capacity of downstream processing equipment, the Robinson refinery could probably run 20,000 BPD of shale oil in a blend with conventional crude oil.

- The possibility of a grass roots refinery is strictly a question of economics. If the Federal government was to adopt a different policy concerning the balance of payments, particularly as related to energy supplies, it could result in a rapid improvement in shale oil economics.

RECORD OF COMMUNICATION

Individual Contacted   Mr. Robert Blomeyer   Date   December 16, 1980

Company   Conoco, Inc.
          Box 2548
          Billings, Montana   59103

Telephone   (406) 252-3841

Mr. Blomeyer was contacted to determine Conoco's ability to refine shale oil into transportation fuels at the Billings refinery. Following are the salient points of that conversation.

- The capacity of the Billings refinery is 56,000 BPD and it is running essentially at capacity. This refinery is presently bottoms limited, meaning that it has a low capacity for processing heavy crudes. Modifications will have to be made in heavy ends processing capability due to the decreased availability of light crudes.

- This refinery would be unable to process crude shale oil since the operating pressure of existing hydrotreaters is only 500-600 psi. These hydrotreaters are used primarily for desulfurization of finished products. Shale oil that had been severely hydrotreated or hydrocracked would be a suitable feedstock for this refinery.

- Approximately 22 percent of the feedstock to this refinery is Wyoming sour crude, 22 percent is Montana sour crude, and the remaining 56 percent is Canadian sour crude obtained through a trade that can be terminated upon 30 days notice.

- Existing refineries will probably be modified before a new refinery is built to process shale oil. The question of refining shale oil is purely a question of economics and a new refinery would probably have to be subsidized by the Federal government.

RECORD OF COMMUNICATION

Individual Contacted___Mr. A. O. Braun_____Date___January 22, 1981___

Company_____UOP Process Division_____
_____20 UOP Plaza_____
_____Algonquin & Mt. Prospect Roads_____
_____Des Plaines, Illinois 60016_____

Telephone___(312) 391-2000_____

Mr. Braun was contacted to determine the cost of performing tests ranging from computer simulations of refineries using shale oil as a feedstock to a 100 barrel pilot plant run. Following are the salient points of that conversation.

- The objective of pilot plant studies would be to confirm the assumptions and results of the computer simulation.

- The Army probably couldn't use the results of a program being funded by the Air Force and being performed by UOP since jet fuel is the desired product of that program rather than diesel fuel and gasoline, the products which have been assumed for estimating purposes. None of the potential flow schemes being examined for the Air Force would be suitable for the Army's use.

- UOP will assume two levels of pilot plant effort (100 barrels and 500 barrels) to give the Army an idea of what different levels of effort would cost. Five hundred barrels is significantly larger than most UOP pilot plants and such a test would be very time consuming and costly.

RECORD OF COMMUNICATION

Individual Contacted___Mr. William Bruner_____Date__December 18, 1980___

Company___Chevron USA, Inc._____
          2351 North 11th West_____
          Box 25117_____
          Salt Lake City, Utah   84125_____

Telephone__(801) 322-1511_____

Mr. Bruner was contacted to determine Chevron's ability to refine shale oil into transportation fuels at the Salt Lake City refinery. Following are the salient points of that conversation.

- The capacity of the Salt Lake City refinery is approximately 45,000 BPD and the refinery is running essentially at capacity.

- Chevron had a program to modify this refinery for crude from the Overthrust Belt, but deferred that program due to secondary recovery efforts in Chevron's Rangely and Altamount fields from which the refinery now obtains its crude oil.

- A test run was made at this refinery with shale oil produced in Occidental's MIS process. In the test run, 300 BPD of shale oil were blended with 5700 BPD of normal resid coker feed. This material was then fed to a delayed coker. The gas oil fraction of the coker distillate was hydrotreated and the remainder of the distillate was run with the regular crude. 1100 psi hydrotreaters were used on the gas oil. These were not the kind of hydrotreaters that would be designed for shale oil and had to be run at a higher severity than normal. If this were done for long periods, the life of the catalyst would be reduced.

- Chevron was supposed to have received 30,000 barrels of shale oil from Occidental with which to run the refinery tests. Chevron had intended to start at low concentration blends and gradually increase the percentage of shale oil to determine how much they could increase the shale oil before they exceeded environmental limits on refinery emissions. However, only 3,000 barrels were received and the scope of the tests had to be drastically reduced.

- There is more refinery capacity in the area than needed which makes it unlikely that a grass roots facility will be built for shale oil. It is more likely that a hydrotreating

Mr. William Bruner
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facility will be constructed. The shale oil would be
hydrotreated and piped out to other refineries as an
upgraded syncrude.

- Refining shale oil will cost approximately $3.50 to
  $4.00 per barrel more than refining conventional crude
  oil. These figures are on an amortized cost basis and
  are incurred because of the necessity to hydrotreat the
  shale oil. However, in the test run, it probably didn't
  cost any more to process the shale oil blend than it
  does to process conventional crude.

RECORD OF COMMUNICATION

Individual Contacted Mr. Al Couper   Date January 26, 1981

Company   Amoco Oil Company
           Naperville Research Center
           Naperville, Illinois

Telephone (312) 420-4843

Mr. Couper was contacted to determine Amoco's ability to refine shale oil into transportation fuels at any of its U. S. refineries. Following are the salient points of that conversation.

- In general, Amoco's refineries don't have any high pressure hydrotreaters. Therefore, they couldn't process any significant amount of raw shale oil. There are some units in which they might be able to blend the feedstocks to produce a feed material that is 1-5% raw shale oil with the remainder being conventional crude oil. Even at that low level, they could run into product quality problems.

- Essentially, Amoco's refineries don't want to handle raw shale oil.

- A severely hydrotreated shale oil could probably be processed in their refineries. The deciding factor would be the amount of nitrogen left in the material. The specific maximum level would depend on the particular refinery unit being examined, but a rule of thumb is approximately 20 ppm. This could be blended with other feeds, particularly a naphtha reformer feed.

- Shale oil is anticipated to be available in 1988 to 1990. Refineries don't know what kinds of crudes they will be processing at that time.

- When shale oil becomes available, refineries will make whatever unit modifications are necessary to take it.

- Amoco has not yet performed any tests with the oil produced from Retort 0 at Tract C-a except to take samples for analysis. They intend to use it in laboratory upgrading projects.

RECORD OF COMMUNICATION

Individual Contacted   Mr. Jay Dewell   Date   December 22, 1980

Company   Phillips Petroleum Company
           Woods Cross, Utah   84087

Telephone   (801) 295-2311

Mr. Dewell was contacted to determine Phillips' ability to refine
shale oil into transportation fuels at the Woods Cross refinery.
Following are the salient points of that conversation.

- The capacity of the Woods Cross refinery is 23,000 BPD
  with no excess capacity.

- Phillips has no existing plans for the expansion or modi-
  fication of this refinery.

- Phillips has some experience with refining raw shale oil
  from the Geokinetics process. An unspecified blend of
  raw shale oil with conventional crude oil produced distillate
  fuels that were unstable and waxy.

- This refinery presently processes Wyoming sweet (65%),
  Wyoming asphaltic (10%), and Rangely (25%) crude oils.
  It doesn't have sufficient hydrotreating capabilities to
  refine raw shale oil nor does it have an adequate hydrogen
  supply. The existing facilities operate at only 400 to
  500 psi. If an upgraded shale oil was available that was
  comparable to one of the crude oils mentioned above, it
  could probably be processed at this refinery.

- A grass roots shale oil refinery would probably not be
  built. Instead, a centrally located hydrotreating facility
  might be built to convert raw shale oil into an upgraded
  syncrude that could be processed in existing refineries.

- The 5-year plan for this refinery includes funds for a hydro-
  treater that could possibly be used to process shale oil.

RECORD OF COMMUNICATION

Individual Contacted___Mr. G. E. Lowe, Jr._____Date___January 7, 1981____

Company____Marathon Oil Company_____
            Robinson, Illinois   62454_____

Telephone___(618) 544-2121_____

        Mr. Lowe was contacted to determine Marathon's ability to refine
shale oil into transportation fuels. Following are the salient
points of that conversation.

- Marathon has looked at alternate refinery feedstocks,
  including shale oil. Mr. Lowe isn't sure that the
  necessary technology is available nor the commitment
  of other refinery operations such as those required to
  produce the large volumes of hydrogen necessary to pro-
  cess shale oil. The hydrogen production capability in-
  volves not only a significant capital investment, but
  also the utilization of valuable products to produce
  hydrogen.

- Mr. Lowe wasn't in a position to discuss Marathon's
  future plans concerning shale oil or other alternate
  feedstocks and suggested that I contact Dr. Al Benham
  at Marathon's corporate headquarters in Findlay, Ohio,
  (419) 422-2121.

RECORD OF COMMUNICATION

Individual Contacted Mr. Robert Mangney   Date December 11, 1980

Company   Asamera Oil Company
           5800 Brighton Blvd.
           Commerce City, Colorado 80022

Telephone (303) 355-7351

Mr. Mangney was contacted to determine Asamera's ability to refine shale oil into transportation fuels at the Commerce City refinery. Following are the salient points of that conversation.

- The capacity of the Commerce City refinery is approximately 45,000 BPD, of which 15,000-18,000 BPD are presently idle. A new crude oil distillation unit came on line in the first part of 1980 which essentially doubled the capacity of the refinery and Asamera has not yet obtained additional crude to fill this available capacity. The necessary crude will probably be obtained over the next five years.

- There are a number of undesirable components in shale oil of which nitrogen is the worst. However, there aren't any problems with shale oil that can't be overcome if the economics justify it.

- The refinery would be unable to accept a raw shale oil feedstock because of the absence of the necessary high pressure hydrotreaters. A substantial capital investment in the form of a hydrotreater would be required before shale oil could be processed in this refinery.

- Crude oil supply contracts are for 1-2 years. Additional crude oil is obtained by spot market purchases.

- The refining industry is presently running at approximately 70 percent capacity. This makes it unlikely that a grass roots refinery will be built to process shale oil. Mr. Mangney doesn't foresee any changes in capacity utilization and anticipates that shale oil will probably be treated prior to being transported to allow it to be processed in existing refineries. He stated that many refineries are already equipped to deal with the sort of problems presented by shale oil.

RECORD OF COMMUNICATION

Individual Contacted____Mr. Richard Masica_____Date__January 5, 1981_____

Company____Texaco, Inc._____
_____Box 320_____
_____Casper, Wyoming 82601_____

Telephone__(307) 234-5377_____

Mr. Masica was contacted to determine Texaco's ability to refine
shale oil into transportation fuels at the Casper refinery. Following
are the salient points of that conversation.

- The capacity of the Casper refinery is 21,000 BPD with no
  excess capacity.

- Texaco has no experience with crude oils from unconventional
  sources. Most of their work has been in the area of coal
  gasification.

- Shale oil as a potential refinery feedstock is being examined
  at the corporate level. The only real problems with it are
  economic ones. The technology exists to refine shale oil.

- Before a guess could be made on whether or not shale oil
  would be a suitable feedstock for this refinery, it would be
  necessary to know the properties of the specific oil in
  question. Laboratory testing of a 5 to 10 gallon sample at
  a cost of $1,000 to $2,000 would determine the parameters
  that are needed to make a proper evaluation.

- Mr. Masica asked not to be quoted as an official represen-
  tative of Texaco. He suggested that future inquiries be
  directed to:

               Mr. James Dunlop
               Vice President of Alternate Energy
               Texaco, Inc.
               2000 Westchester Avenue
               White Plains, New York 10604

RECORD OF COMMUNICATION

Individual Contacted___ Mr. Don McCullum _____ Date___January 8, 1981_____

Company___ Tosco Corporation _____
_____10100 Santa Monica Blvd. _____
_____Los Angeles, California 90067 _____

Telephone__(213) 552-7349 _____

Mr. McCullum was contacted to determine the cost to produce 100 barrels of shale oil using the TOSCO II pilot plant retort in Golden, Colorado. Following are the salient points of that conversation.

- A pilot plant run at Tosco's Golden facility would depend on:
  - The location of the shale source.
  - What the Army would do to the shale.
  - What the Army's intent is.
  - Whether Tosco had time and space to make such a run.

- The cost of the program would be a function of how much the Army expects Tosco to do.

- The Army needs to outline the parameters of what they want to do.

- Mr. McCullum said that it isn't necessary to make a shale oil production run and refining runs to get the characteristics of the resulting distillate fuels. There is enough known about the characteristics of the shale and the retorting conditions to predict fuel characteristics.

- Mr. McCullum felt that if Tosco could obtain a sample of the shale that the Army thinks they will be using, Tosco can make some predictions.

- Without knowing what the Army's plan and scope of work would be, Mr. McCullum was reluctant to estimate the cost of such a program. He wanted to know a lot more detail.

- It is easy to make distillate fuels from shale oil, but there are other products that also need to be considered in addition to the distillate fraction. If only one product is to be produced, there is the question of disposition of the other products.

Mr. Don McCullum
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- It would cost "a lot of money" to determine the optimum
  set of refinery conditions to use to maximize the pro-
  duction of the fuels in which the Army is interested.

- In order to respond, Mr. McCullum requested a written
  description of CSMRI's scope of work with the Army, a
  description of our objectives, and a description of what
  we would like Tosco to do.

RECORD OF COMMUNICATION

Individual Contacted___Mr. R. G. McNamara_____Date___December 18, 1980___

Company____Little America Refining Company_____
_____Box 510_____
_____Evansville, Wyoming   82636_____

Telephone___(307) 265-2800_____

Mr. McNamara was contacted to determine Little America's ability to refine shale oil into transportation fuels at the Evansville refinery. Following are the salient points of that conversation.

- The capacity of the Evansville refinery is 24,500 BPD and the refinery is running essentially at capacity.

- There are presently no plans for expansion or modification since they are confident that they will continue to obtain crude oil from their present suppliers.

- Mr. McNamara indicated that Little America has had no experience with crude oils from unconventional sources such as oil shale or tar sands.

- Mr. McNamara was unable to comment on Little America's ability to process shale oil at this refinery, but did say that he felt shale oil is a "terrible venture" that will always have to be subsidized. He cited unrealistic recovery costs as the reason and said that cracking residual oil is better than using shale oil.

RECORD OF COMMUNICATION

Individual Contacted___Mr. Ken Roane_____Date___December 19, 1980___

Company___Husky Oil Company_____
          Box 380_____
          Cody, Wyoming 82414_____

Telephone Denver Office: (303) 370-1300_____
           Cody Office: (307) 578-1353_____
                            (307) 578-1000_____

Mr. Roane was contacted to determine Husky's ability to refine shale oil into transporation fuels at either the Salt Lake City refinery or the Cody refinery. Following are the salient points of that conversation.

- Mr. Roane, a senior engineer under the Vice President of Refining, used to work at Geokinetics and is much more enthusiastic about synthetic fuels from shale than from coal.

- Mr. Roane advocates hydrotreating the whole crude shale oil to a synthetic crude which can then be fed to an existing refinery instead of hydrotreating individual streams after the crude shale oil has been fractionated or coking the crude shale oil.

- Husky's Salt Lake City refinery presently processes Altamount wax crude from the Altamount and Blue Bell fields of the Uintah Basin in Utah. However, the 25,000 BPD refinery is running only about 7,500 BPD. Alternate feedstocks for this refinery might come from Overthrust crude suppliers.

- Mr. Roane's opinion is that shale oil producers don't have the funds to upgrade shale oil to a usable crude. He feels that, as processors, this is one of Husky's strong points and that they should build an upgrading plant that is large enough to keep the Salt Lake City refinery supplied with crude with the possibility of selling excess syncrude to other refineries.

- This idea hasn't yet been presented to management. For a first presentation, they will guess at equipment requirements and develop costs on that basis. If management shows more interest, the next step will be a more detailed cost estimate.

- No thought has yet been given to possible environmental problems. Two years would be required for permitting and another three years for construction if they started now. He thinks that the industry will be producing 30,000 to 60,000 BPD of raw shale oil by then.

- No refiner in the Salt Lake City area has excess hydrogen that could be used to hydrotreat shale oil.

RECORD OF COMMUNICATION

Individual Contacted   Mr. E. T. Robinson   Date   November 18, 1980

Company   Standard Oil Company (Ohio) (Sohio)
             Research and Development
             4400 Warrensville Center Road
             Cleveland, Ohio 44128

Telephone   (216) 575-4279

Mr. Robinson was contacted to obtain information concerning the shale
oil refinery run made at the Toledo, Ohio refinery. Following are
the salient points of that conversation.

- There were three reports written as a result of the entire
  program conducted by Sohio. The Phase I report covered the
  pilot plant work. The Phase II report was a short summary
  of the refinery test run. The Phase III report was a detailed
  description of the refinery run and the analysis of the pro-
  ducts that were produced.

- There were proprietary and non-proprietary versions of the
  Phase I report. The non-proprietary report should be avail-
  able from the Navy.

- The Phases II and III reports were also submitted to the Navy,
  but Mr. Robinson wasn't sure as to their proprietary or non-
  proprietary status.

- Lt. Commander Lawrence Lukens was the scientific officer for
  this project. He is presently located in the Forrester
  Building in Washington, D. C.

- The full reports contain more detailed information on the
  acid treating process that was used as the final processing
  step, but Sohio doesn't feel that acid treating is a viable
  route because of the sludge that is produced. There is no
  acceptable way to dispose of the acid sludge. The sludge
  comprises approximately 5 wt percent of the total oil that
  is treated and is a function of hydrotreating severity. In-
  creased denitrification in hydrotreating leads to reduced
  volumes of sludge. The sludge is difficult to dispose of.
  Sohio sold their sludge to an acid sludge treating firm.
  This method was adequate for the small amount of sludge pro-
  duced, but would probably be an unacceptable disposal method
  if 50-100 MBPD of shale oil was fed to the refinery simply
  because of the volume of sludge produced.

- The products from the Gary Western refinery run were contami-
  nated with gilsonite that was present in the storage tanks
  into which the refined products were pumped. This is the rea-
  son that the jet fuel quality was unacceptable.

RECORD OF COMMUNICATION

Individual Contacted   Mr. Ron Runge   Date   January 8, 1981

Company   Union Oil Company of California
            Box 339
            Lemont, Illinois   60439

Telephone   (312) 257-7761

Mr. Runge was contacted to determine Union's ability to refine shale
oil into transportation fuels at the Lemont refinery. Following are
the salient points of that conversation.

- The capacity of the Lemont refinery is 150,000 BPD. Mr.
  Runge indicated that there is some excess capacity but was
  not specific.

- It is difficult to distinguish between conventional crude
  oil and upgraded shale oil that has been processed to remove
  contaminants and reduce the pour point.

- Union plans to upgrade the shale oil to a syncrude at the
  retorting site which will make it possible to refine the oil
  at any of Union's refineries. Mr. Runge assumes that some
  shale oil would be processed at the Lemont refinery.

- The upgrading facilities at the retorting site will be able
  to process up to 50,000 barrels of raw shale oil per day.
  Any oil produced in excess of this will have to be treated
  elsewhere.

- Union has developed a catalytic technique by which the pour
  point of shale oil can be reduced making the oil transport-
  able in a pipeline.

- Union feels that shale oil has the potential for being a good
  lube stock and is investigating this potential use.

- Union's marketing plans include three options:
  1) Trade the upgraded syncrude to local refineries
      in exchange for conventional crude elsewhere.
  2) Pipeline the syncrude to a Texas refinery.
  3) Pipeline the syncrude to Chicago.

RECORD OF COMMUNICATION

Individual Contacted___Mr. Schauer_____   Date___December 22, 1980___

Company____Amoco Oil Company_____
          Box 160_____
          Casper, Wyoming   82602_____

Telephone___(307) 265-3390_____

Mr. Schauer was contacted to determine Amoco's ability to refine shale oil into transportation fuels at the Casper refinery. Following are the salient points of that conversation.

- The capacity of the Casper refinery is 44,500 BPD.

- Amoco has had no experience with synthetic crudes at this refinery. They typically refine Wyoming or Montana crudes.

- This refinery would be unable to refine raw shale oil because of the absence of a high pressure hydrotreater. The operating pressure of the reformer feed hydrotreater is only 300 psi.

- A grass roots refinery would probably not be built to process shale oil since shale oil producers will be upgrading the raw oil to a syncrude that can be processed in existing refineries.

- If Amoco did refine shale oil, it would probably be done at the Salt Lake City refinery because of its proximity to the western slope of Colorado and the presence of a pipeline from Rangely, Colorado to Salt Lake City.

RECORD OF COMMUNICATION

Individual Contacted Mr. Schneider   Date   December 19, 1980

Company   Husky Oil Company
           Box 1588
           Cheyenne, Wyoming   82001

Telephone   (307) 634-3551

Mr. Schneider was contacted to determine Husky's ability to refine
shale oil into transportation fuels at the Cheyenne refinery. Fol-
lowing are the salient points of that conversation.

- The capacity of the Cheyenne refinery is 35,000 BPD with
  about 5,000 BPD of unused capacity. Husky has just com-
  pleted the addition of a delayed coker and the associated
  debottlenecking of existing processing units.

- This refinery is beginning to process more sour crudes and
  asphalt crudes.

- Husky has no experience with crude oils from unconventional
  sources.

- This refinery would be unable to accept raw shale oil as a
  feedstock due to the absence of high pressure hydrotreaters.
  They presently have 500-600 psi distillate and reformer feed
  hydrotreaters.

- The possibility of processing shale oil is being examined in
  Husky's corporate offices. If Husky decides to pursue the
  matter, one refinery, probably Salt Lake City, would probably
  be modified for shale oil processing and the crude oil nor-
  mally processed at Salt Lake City would be diverted to Cheyenne.

- Mr. Schneider suggested that we contact Mr. Ken Roane in
  Husky's corporate offices. Mr. Roane is on the staff of the
  Vice President of Refining.

RECORD OF COMMUNICATION

Individual Contacted Mr. Jack Sikonia   Date   January 29, 1981

Company   UOP Process Division
           20 UOP Plaza
           Algonquin & Mt. Prospect Roads
           Des Plaines, Illinois 60016

Telephone (312) 391-3263

Mr. Sikonia responded to CSMRI's request to UOP for an estimate of the
cost to perform computer simulations and pilot plant refining tests
using a shale oil feedstock. Following are the salient points of that
conversation.

- The first phase of the program would involve a preliminary
  cost estimate, definition of the flow sheet and the perform-
  ance of each unit in the flow scheme, utility cost estimates,
  and a total cost estimate. This program would cost $50,000
  to $100,000.

- The second phase would be pilot plant runs to confirm the
  estimates of Phase I and would cost $200,000 to $300,000.

- These figures are just rough estimates. If the Army decides
  to pursue a production program such as this, they will need
  to get directly in touch with UOP to provide specific infor-
  mation concerning what results they expect to get from the
  program. UOP would then have the opportunity to respond with
  a more complete and detailed cost estimate.

- Mr. Sikonia wanted to know if this ballpark estimate would
  have to be supported by a UOP name. CSMRI responded that we
  would like to use UOP's name, but would not do so if UOP objected.

RECORD OF COMMUNICATION

Individual Contacted __Mr. Don Stuewe__   Date __December 18, 1980__

Company___ Sinclair Oil Corporation___
          ___Box 277___
          ___Sinclair, Wyoming   82334___

Telephone___ (307) 324-3404___

Mr. Stuewe was contacted to determine Sinclair's ability t‹   ‹ne
shale oil into transportation fuels at the Sinclair refiner‹. Fol-
lowing are the salient points of that conversation.

- The capacity of the Sinclair refinery is 60,000 BPD and
  the refinery is running essentially at capacity.

- Sinclair has no existing plans for expansion or modifica-
  tions. They would consider using shale oil as a feedstock,
  but only if nothing else was available. They are more inter-
  ested in staying in business which means processing the finest
  quality crudes they can obtain and making modifications only
  when necessary.

- Sinclair made a small test run with shale oil. The run was
  unsuccessful due to a lack of necessary time and technical
  skills. The product was unable to meet color and odor speci-
  fic‹tions.

- This refinery would be unable to process shale oil due to the
  absence of a high pressure hydrotreater and an adequate source
  of hydrogen. The only hydrotreating facilities that are avail-
  able are 500 psi units designed to hydrotreat reformer feedstocks.

- There is a low probability that a grass roots refinery will be
  built to porcess shale oil. Only the large oil companies
  (Exxon or Union) would be able to do it. Mr. Stuewe feels
  that windfall profits tax money should be made available for
  the construction of such a facility.

- This refinery is located such that they should be interested
  in taking on the problems that are associated with processing
  shale oil and Mr. Stuewe is examining the situation closely.

RECORD OF COMMUNICATION

Individual Contacted   Mr. Ron Trottier   Date   January 9, 1981

Company   Energy Cooperative, Inc.
           3500 Indianapolis Blvd.
           East Chicago, Indiana   45312

Telephone   (219) 397-0924

Mr. Trottier was contacted to determine Energy Cooperative's ability to refine shale oil into transportation fuels. Following are the salient points of that conversation.

- The capacity of the East Chicago refinery is 126,000 BPD. It is presently operating at approximately 70 percent capacity.

- Energy Cooperative will probably add a hydrodesulfurization unit to permit heavier, higher sulfur crudes to be refined. The operating pressure of this unit will be approximately 1000 psi.

- Energy Cooperative has no experience with crude oil from unconventional sources.

- This refinery doesn't have a suitable hydrotreater or hydrogen source to process crude shale oil. However, an upgraded shale oil could be processed, especially after the addition of the new hydrodesulfurization unit.

- The location in which shale oil is refined will depend on where there is a market for the end products.

- Energy Cooperative will begin looking at upgraded shale oil as a potential refinery feedstock when availability falls within the 5-year horizon.

RECORD OF COMMUNICATION

Individual Contacted Mr. Don Unruh   Date December 11, 1980

Company   Conoco, Inc.
             5801 Brighton Blvd.
             Commerce City, Colorado 80022

Telephone (303) 575-6213

Mr. Unruh was contacted to determine Conoco's ability to refine shale
oil into transportation fuels at the Commerce City refinery. Following
are the salient points of that conversation.

- The capacity of the Commerce City refinery is 33,500 BPD
  and the refinery is running essentially at capacity.

- At present, there are no plans for expansion at this
  refinery nor are there any anticipated changes in the
  type of crude oil used as feed material.

- The only experience that Conoco has with refining crude
  oils from unconventional sources is a test run approxi-
  mately 10 yr ago at a refinery in Duluth, Minnesota in
  which oil from oil sands was utilized as a feedstock.
  Significant problems were encountered with running streams
  from this material through a catalytic reformer. Excessive
  coke laydown on the reformer catalyst caused rapid deacti-
  vation of that catalyst.

- The Commerce City refinery doesn't have the necessary hydro-
  treating facilities to run crude shale oil. However, the
  availability of an upgraded (hydrotreated) shale oil might
  make Conoco more receptive to the idea of processing shale
  oil in this refinery.

- Although a specific figure was not mentioned, Mr. Unruh
  estimated that the cost of processing shale oil would prob-
  ably be higher than the cost of processing conventional
  crude oil.

- The existing pipeline network eliminates or severely reduces
  the possibility of a grass roots refinery being built to re-
  fine shale oil. This doesn't eliminate the possibility of a
  large company such as Exxon building a refinery on the western
  slope of Colorado, but it is more likely that shale oil will
  be pipelined to existing refining centers.

RECORD OF COMMUNICATION

Individual Contacted   Mr. Stan Weil   Date   December 11, 1980

Company   Gary Western Company
            Fruita, Colorado 81521

Telephone   (303) 858-3611

Mr. Weil was contacted to determine Gary Western's ability to refine
shale oil into transportation fuels at the Fruita refinery. Following
are the salient points of that conversation.

- The capacity of the Fruita refinery is 11,000 BPD and the
  refinery is running at capacity.

- Gary Western performed a refining run in 1975 with whole
  crude shale oil. The refinery wasn't suited for this feed-
  stock and there was a considerable amount of contamination
  and halted operation. This refinery doesn't have suitable
  hydrotreating capabilities to accept crude shale oil as a
  feedstock.

- An upgraded shale oil could be accepted by any refinery.

- Gary Western is presently performing a DOE feasibility study
  for a complete shale oil refinery with a capacity of 10,000
  BPD.

RECORD OF COMMUNICATION

Individual Contacted   Mr. A. R. Williams   Date   January 8, 1981

Company   Shell Oil Company
           Box 262
           Wood River, Illinois   62095

Telephone   (618) 254-7371

Mr. Williams was contacted to determine Shell's ability to refine shale oil into transportation fuels at the Wood River refinery. Following are the salient points of that conversation.

- The capacity of the Wood River refinery is 283,000 BPD with no excess capacity.

- Shell Oil has some experience with refining shale oil stemming from their involvement at Colorado Lease Tract C-b. Processing work was discontinued at the same time that their activities at C-b were halted.

- Shell has a corporate group that continues to examine all potential sources of crude oil, including shale oil.

- This refinery has a large hydrogen plant that is presently idle. It also has hydrocracking facilities. Mr. Williams would not reveal the operating pressure of the hydrocracking facilities, but he implied that the pressure is high enough to process shale oil.

- An analysis of the shale oil in question would be necessary to determine whether or not it would be processed at this refinery.

RECORD OF COMMUNICATION

Individual Contacted Mr. Loren Young   Date   January 7, 1981

Company   Superior Oil Company
           2750 South Shoshone
           Englewood, Colorado 80110

Telephone (303) 934-2215

      Mr. Young was contacted to determine the cost of performing a shale
oil production run using Superior's facilities. He responded that
performing a test run such as this would be quite a deviation from
Superior's normal policy and that they would not be interested in
doing so.